UTAH DIVISION OF OIL, GAS AND MINING

REMARKS: WELL LOG X ELECTRIC LOGS X FILE X WATER SANDS ____ LOCATION INSPECTED ____ SUB. REPORT/ABD. ____

Commenced Inj. 11-13-92 SDW

DATE FILED 1-30-78

LAND: FEE & PATENTED STATE LEASE NO. PUBLIC LEASE NO. UTAH 0144869 INDIAN

DRILLING APPROVED: 1-27-78

SPUDDED IN: 2-9-78

COMPLETED: 4-5-78 SGW PUT TO PRODUCING: 4-5-78

INITIAL PRODUCTION: 5863' MCF/D

GRAVITY A.P.I.

GOR:

PRODUCING ZONES: 6068'-6920' Wasatch

TOTAL DEPTH: 7025'

WELL ELEVATION: 4785' KB

DATE ABANDONED:

FIELD: Natural Buttes

UNIT: Natural Buttes

COUNTY: Uintah

WELL NO. Natural Buttes Unit 21-20B API NO: 43-047-30359

LOCATION 1037' FT. FROM (N) ~~(S)~~ LINE. 1033' FT. FROM (E) ~~(W)~~ LINE. NE NE ¼ – ¼ SEC. 20

TWP.	RGE.	SEC.	OPERATOR	TWP.	RGE.	SEC.	OPERATOR
9S	20E	20	Enron / Coastal ~~BELCO DEVELOPMENT CORP.~~				

GEOLOGIC TOPS:

Green River 1704'
Wasatch 5210'
Chapita Wells 5774'
Buck Canyon 6224'

P.O. Box 250
Big Piney, Wyoming 83113
Telephone (307) 276-3331

file

Belco Petroleum Corporation

Belco

January 24, 1978

Mr. Edgar W. Guynn, District Engineer
United States Geological Survey
8440 Federal Building
Salt Lake City, Utah 84138

RE: Natural Buttes Unit 21-20B
NE NE Section 20, T9S, R20E
Uintah County, Utah
Natural Buttes Unit 22-27B
SW NE Section 27, T10S, R21E
Uintah County, Utah
Natural Buttes Unit 24-32B
NE NE Section 32, T9S, R20E
Uintah County, Utah
Natural Buttes Unit 25-20B
SW NW Section 20, T9S, R21E
Uintah County, Utah
Natural Buttes Unit 26-13B
SE SE Section 13, T10S, R20E
Uintah County, Utah

RECEIVED
JAN 26 1978

Dear Mr. Guynn:

Attached are Applications for Permit to Drill, Survey Plats, BOP Diagrams and Surface Use and Operating Plans for the referenced wells.

Very truly yours,

BELCO PETROLEUM CORPORATION

Leo R. Schueler /RAS

Leo R. Schueler
District Manager

RAS/rgt

Attachments
cc: Utah Division of Oil, Gas, & Mining
Gas Producing Enterprises, Inc., Mr. Wendell Cole
Houston
Denver
File

RECEIVED
JAN 26 1978

Form 9-331 C
(May 1963)

SUBMIT IN T. CATE*
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1425.

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

APPLICATION FOR PERMIT TO DRILL, DEEPEN, OR PLUG BACK

5. LEASE DESIGNATION AND SERIAL NO.
UTAH 0144869

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
UTE (SURFACE)

7. UNIT AGREEMENT NAME
NATURAL BUTTES UNIT

8. FARM OR LEASE NAME

9. WELL NO.
21-20B

10. FIELD AND POOL, OR WILDCAT
NBU - WASATCH

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
SEC. 20, T9S, R20E

12. COUNTY OR PARISH
UINTAH

13. STATE
UTAH

1a. TYPE OF WORK
DRILL [X] DEEPEN [ ] PLUG BACK [ ]

b. TYPE OF WELL
OIL WELL [ ] GAS WELL [X] OTHER SINGLE ZONE [ ] MULTIPLE ZONE [ ]

2. NAME OF OPERATOR
BELCO DEVELOPMENT CORPORATION

3. ADDRESS OF OPERATOR
P. O. BOX 250, BIG PINEY, WYOMING 83113

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.*)
At surface
1037' FNL & 1033' FEL (NE NE)
At proposed prod. zone
SAME

RECEIVED
JAN 26 1978

14. DISTANCE IN MILES AND DIRECTION FROM NEAREST TOWN OR POST OFFICE*

15. DISTANCE FROM PROPOSED* LOCATION TO NEAREST PROPERTY OR LEASE LINE, FT. (Also to nearest drlg. unit line, if any) 287'

16. NO. OF ACRES IN LEASE 920

17. NO. OF ACRES ASSIGNED TO THIS WELL

18. DISTANCE FROM PROPOSED LOCATION* TO NEAREST WELL, DRILLING, COMPLETED, OR APPLIED FOR, ON THIS LEASE, FT.

19. PROPOSED DEPTH 7200'

20. ROTARY OR CABLE TOOLS ROTARY

21. ELEVATIONS (Show whether DF, RT, GR, etc.)
4770' NAT. GL

22. APPROX. DATE WORK WILL START*
2/78

23. PROPOSED CASING AND CEMENTING PROGRAM

SIZE OF HOLE	SIZE OF CASING	WEIGHT PER FOOT	SETTING DEPTH	QUANTITY OF CEMENT
12¼"	9-5/8"	36.0# K-55	200'	200 sx
7-7/8"	4½"	11.6# K-55	7200'	600 sx

1. Surface Formation - Uintah
2. Est. Log Tops: Green River 1440', Wasatch 5180'.
3. Anticipate gas in the Wasatch at 5180', 5760', & 6525'.
4. Casing Design: New casing as above.
5. Min. BOP: 8" 3000 psi hydraulic double gate BOP. Test to 1000 psi prior to drilling surface plug. Test daily & on each trip for bit.
6. Mud Program: A water base gel-chemical mud weighted to 10.5 ppg will be used to control the well.
7. Auxiliary Equip: 2" 3000 psi choke manifold and kill line, kelly cock, stabbing valve and visual mud monitoring.
8. Run DIL, CNL-FDC-GR w/Caliper logs. Possible 2 DST's. No cores are anticipated.
9. No abnormal pressures or problems are anticipated.
10. Operations will begin approx 2/78 and end approx 3/78.

IN ABOVE SPACE DESCRIBE PROPOSED PROGRAM: If proposal is to deepen or plug back, give data on present productive zone and proposed new productive zone. If proposal is to drill or deepen directionally, give pertinent data on subsurface locations and measured and true vertical depths. Give blowout preventer program, if any.

24.
SIGNED Robert Springman TITLE ENGINEERING TECHNICIAN DATE 1/24/78

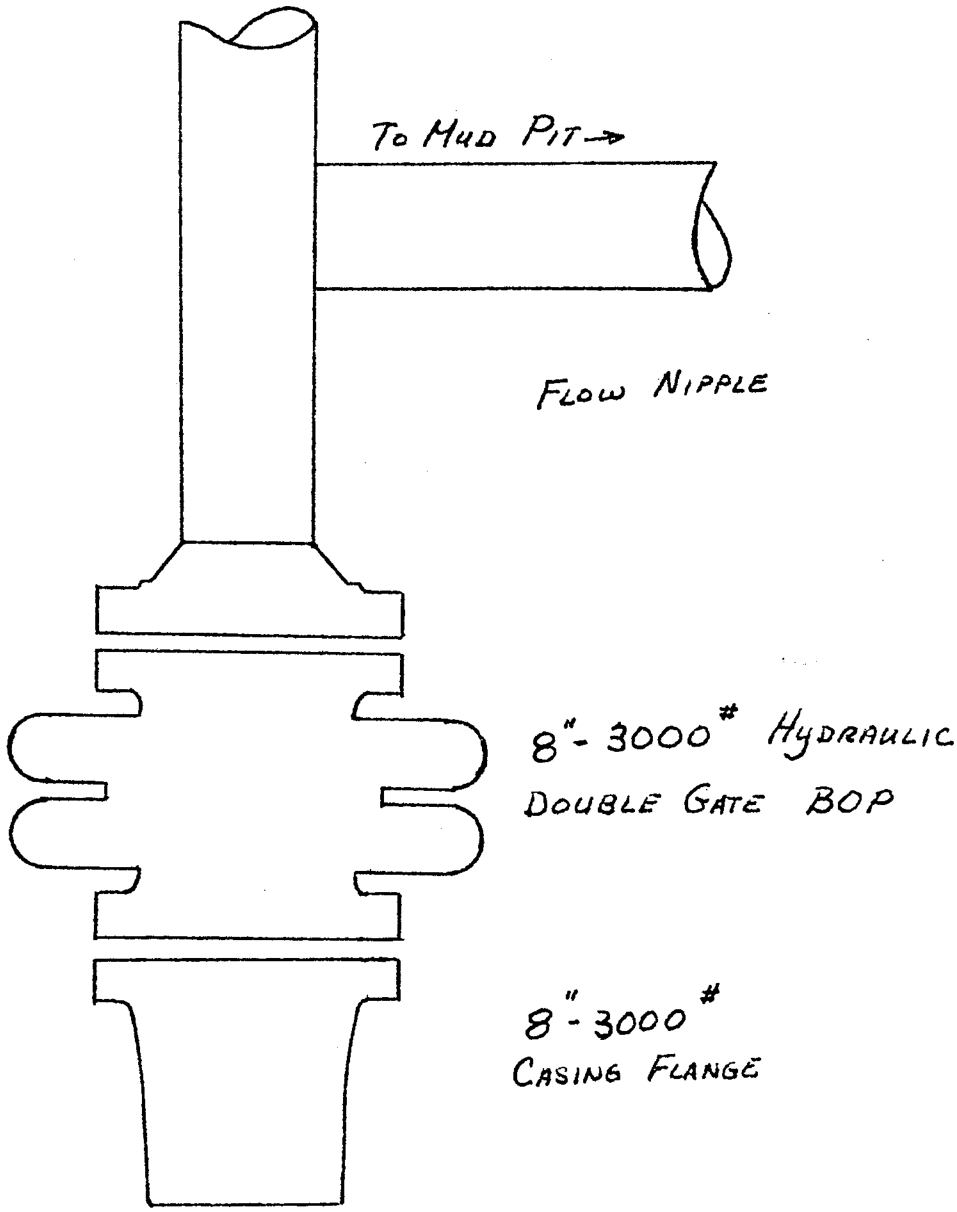
(This space for Federal or State office use)

PERMIT NO. 43-047-30359 APPROVAL DATE

APPROVED BY THE DIVISION OF
OIL, GAS, AND MINING
DATE: 1-27-78
BY: C.B. Feight

APPROVED BY TITLE DATE
CONDITIONS OF APPROVAL, IF ANY:

*See Instructions On Reverse Side



Minimum BOP
Diagram

STATE OF UTAH
DIVISION OF OIL, GAS AND MINING

** FILE NOTATIONS **

Date: Jan. 27.

Operator: Belco Pet.

Well No: Natural Buttes Unit 21-20B

Location: Sec. 20 T. 9S R. 20E County: Uintah

File Prepared: /✓/ *Entered on N.I.D.:* /✓/

Card Indexed: /✓/ *Completion Sheet:* /✓/

API NUMBER: 43-047-30359

CHECKED BY:

Administrative Assistant ___

Remarks:

Petroleum Engineer ___

Remarks:

Director ___

Remarks:

INCLUDE WITHIN APPROVAL LETTER:

Bond Required: /___/ *Survey Plat Required:* /___/

Order No. ___ /___/ *Surface Casing Change* /___/
to ___

Rule C-3(c), Topographic exception/company owns or controls acreage within a 660' radius of proposed site /___/

O.K. Rule C-3 /___/ *O.K. In* Nat Butte *Unit* /✓/

Other:

/✓/ ~~Letter Written~~ *Approved*

Form 9-331 C
(May 1963)

SUBMIT IN [illegible]LICATE*
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1425.

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

APPLICATION FOR PERMIT TO DRILL, DEEPEN, OR PLUG BACK

1a. TYPE OF WORK
DRILL [X] DEEPEN [ ] PLUG BACK [ ]

b. TYPE OF WELL
OIL WELL [ ] GAS WELL [X] OTHER SINGLE ZONE [ ] MULTIPLE ZONE [ ]

2. NAME OF OPERATOR
BELCO DEVELOPMENT CORPORATION

3. ADDRESS OF OPERATOR
P. O. BOX 250, BIG PINEY, WYOMING 83113

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.*)
At surface
1037' FNL & 1033' FEL (NE NE)
At proposed prod. zone
SAME

RECEIVED
FEB 2 1978
DIVISION OF OIL, GAS, & MINING

5. LEASE DESIGNATION AND SERIAL NO.
UTAH 0144869

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
UTE (SURFACE)

7. UNIT AGREEMENT NAME
NATURAL BUTTES UNIT

8. FARM OR LEASE NAME

9. WELL NO.
21-20B

10. FIELD AND POOL, OR WILDCAT
NBU - WASATCH

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
SEC. 20, T9S, R20E

14. DISTANCE IN MILES AND DIRECTION FROM NEAREST TOWN OR POST OFFICE*

12. COUNTY OR PARISH
UINTAH

13. STATE
UTAH

15. DISTANCE FROM PROPOSED* LOCATION TO NEAREST PROPERTY OR LEASE LINE, FT. (Also to nearest drlg. unit line, if any)
287'

16. NO. OF ACRES IN LEASE
920

17. NO. OF ACRES ASSIGNED TO THIS WELL

18. DISTANCE FROM PROPOSED LOCATION* TO NEAREST WELL, DRILLING, COMPLETED, OR APPLIED FOR, ON THIS LEASE, FT.

19. PROPOSED DEPTH
7200'

20. ROTARY OR CABLE TOOLS
ROTARY

21. ELEVATIONS (Show whether DF, RT, GR, etc.)
4770' NAT. GL

22. APPROX. DATE WORK WILL START*
2/78

23. PROPOSED CASING AND CEMENTING PROGRAM

SIZE OF HOLE	SIZE OF CASING	WEIGHT PER FOOT	SETTING DEPTH	QUANTITY OF CEMENT
12¼"	9-5/8"	36.0# K-55	200'	200 sx
7-7/8"	4½"	11.6# K-55	7200'	600 sx

1. Surface Formation - Uintah
2. Est. Log Tops: Green River 1440', Wasatch 5180'.
3. Anticipate gas in the Wasatch at 5180', 5760', & 6525'.
4. Casing Design: New casing as above.
5. Min. BOP: 8" 3000 psi hydraulic double gate BOP. Test to 1000 psi prior to drilling surface plug. Test daily & on each trip for bit.
6. Mud Program: A water base gel-chemical mud weighted to 10.5 ppg will be used to control the well.
7. Auxiliary Equip: 2" 3000 psi choke manifold and kill line, kelly cock, stabbing valve and visual mud monitoring.
8. Run DIL, CNL-FDC-GR w/Caliper logs. Possible 2 DST's. No cores are anticipated.
9. No abnormal pressures or problems are anticipated.
10. Operations will begin approx 2/78 and end approx 3/78.

IN ABOVE SPACE DESCRIBE PROPOSED PROGRAM: If proposal is to deepen or plug back, give data on present productive zone and proposed new productive zone. If proposal is to drill or deepen directionally, give pertinent data on subsurface locations and measured and true vertical depths. Give blowout preventer program, if any.

24.
SIGNED Robert Springman TITLE ENGINEERING TECHNICIAN DATE 1/24/78

(This space for Federal or State office use)

PERMIT NO. APPROVAL DATE

APPROVED BY (ORIG. SGD.) E. W. GUYNN TITLE DISTRICT ENGINEER DATE [illegible] 1978

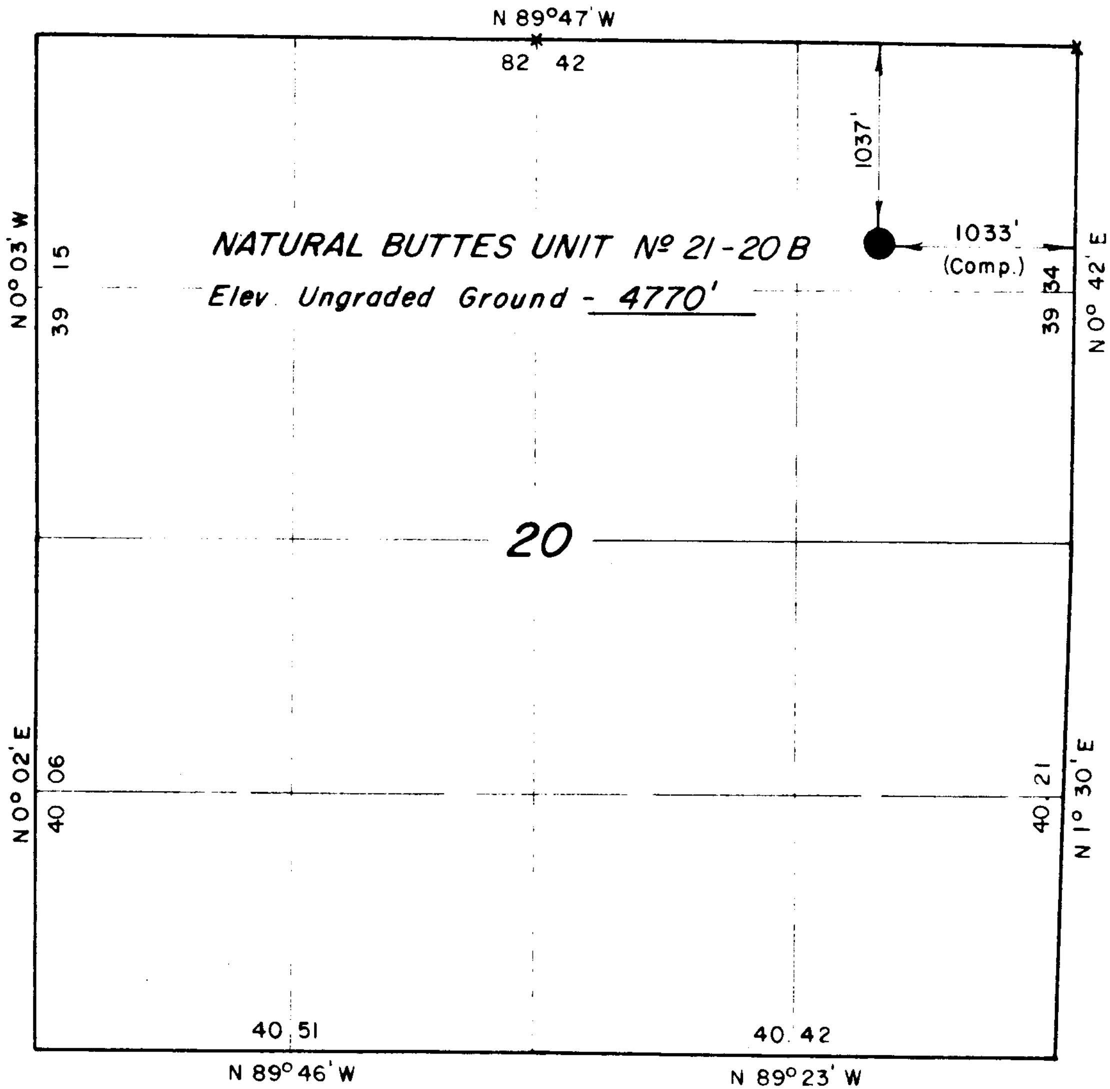
CONDITIONS OF APPROVAL, IF ANY:

NOTICE OF APPROVAL

State O+G

*See Instructions On Reverse Side

T 9 S, R 20 E, S.L.B.& M.



X = Section Corners Located

PROJECT

BELCO PETROLEUM CORPORATION

Well location, *NATURAL BUTTES UNIT Nº 21 - 20 B*, located as shown in the NE 1/4 NE 1/4 Section 20, T 9 S, R 20 E, S.L.B.& M. Uintah County, Utah.

NOTE

Elev	Ref	Pt	200'	East	=	4771.90'
"	"	"	250'	"	=	4772.60'
"	"	"	200'	West	=	4768.20'
"	"	"	200'	South	=	4770.70'
"	"	"	250'	"	=	4771.10'
"	"	"	200'	North	=	4769.90'

CERTIFICATE

[illegible] CERTIFY THAT THE ABOVE PLAT WAS PREPARED FROM FIELD NOTES OF ACTUAL SURVEYS MADE BY ME OR UNDER MY SUPERVISION AND THAT THE SAME ARE [illegible] AND CORRECT TO THE BEST OF MY KNOWLEDGE AND BELIEF.

REGISTERED LAND SURVEYOR
REGISTRATION Nº 2454
STATE OF UTAH

UINTAH ENGINEERING & LAND SURVEYING
P.O. BOX Q — 110 EAST - FIRST SOUTH
VERNAL, UTAH - 84078

SCALE	DATE
1" = 1000'	1 / 19 / 78
PARTY R.K. J.B. BFW	REFERENCES GLO Plat
WEATHER Cold	FILE BELCO

ATTACHMENT 2-A

SUMMARY OF ENVIRONMENTAL IMPACT EVALUATION

EIA NO. 923
DATE 1/31

OPERATOR. Belco
LEASE # Utah 0144869
WELL NO. N-20B
LOC NE NE SEC. 20
T. 9S R. 20E
COUNTY Uintah STATE Utah
FIELD NBU-WASATCH
USGS Wilson
~~BLM~~ Lynn Hall
REP: Geo Smith.
DIRT

[O] ENHANCES
[ ] NO IMPACT
[/] MINOR IMPACT
[X] MAJOR IMPACT

		Construction				Pollution				Drilling Production						Transport Operations			Accidents		Others
		Roads, bridges, airports	Transmission lines, pipelines	Dams & impoundments	Others (pump stations, compressor stations, etc.)	Burning, noise, Junk disposal	Liquid effluent discharge	Subsurface disposal	Others (toxic gases, noxious gas, etc.)	Well drilling	Fluid removal (Prod. wells, facilities)	Secondary Recovery	Noise or obstruction of scenic views	Mineral processing (ext. facilities)	Others	Trucks	Pipelines	Others	Spills and leaks	Operational failure	
Land Use: Forestry	NA																				
Grazing	/	/		/		/				/						/			/	/	
Wilderness	NA																				
Agriculture	NA																				
Residential-Commercial	NA																				
Mineral Extraction	NA																				
Recreation	/	/		/		/				/						/			/	/	
Scenic Views	/	/		/		/				/						/			/	/	
Parks, Reserves, Monuments	NA																				
Historical Sites				NONE			KNOWN														
Unique Physical Features	NA																				
Flora & Fauna: Birds	/	/		/		/				/			/			/			/	/	
Land Animals	/	/		/		/				/			/			/			/	/	
Fish	NA																				
Endangered Species				NONE			KNOWN														
Trees, Grass, Etc.	/	/		/		/				/						/			/	/	
Phy. Charact.: Surface Water	NA																				
Underground Water	?																				
Air Quality	/	/		/		/				/						/			/	/	
Erosion	/	/		/		/				/						/			/	/	
Other																					
Effect On Local Economy	✓	O								O						O					
Safety & Health	✓	/		/		/				/						/			/	/	
~~Others~~ Note:	Location well staked & marked.																				

Orig file
cc: Reg. Denver
Sta - St [illegible] w/o matrix
State Oil and Gas

EIA NO.

LEASE Utah 0144869 DATE 1/31/78

WELL NO. 21-20B

LOCATION: NE ¼ NE ¼, SEC. 20 , T. 9S , R. 20E

FIELD NBU - WASATCH COUNTY Uintah STATE Utah.

ENVIRONMENTAL IMPACT ANALYSIS - ATTACHMENT 2-B

I. PROPOSED ACTION

Belco Development Corp. (COMPANY) PROPOSES TO DRILL ~~AN OIL AND~~ GAS TEST WELL WITH ROTARY TOOLS TO ABOUT 7200 FT. TD. 2) TO CONSTRUCT A DRILL PAD 325 FT. X 200 FT. AND A RESERVE PIT 150 FT. X 100 FT. 3) TO CONSTRUCT ✓ FT. WIDE X ✓ MILES ACCESS ROAD AND UPGRADE ✓ FT. WIDE X ✓ MILES ACCESS ROAD FROM AN EXISTING AND IMPROVED ROAD. TO CONSTRUCT [X] GAS ~~[ ] OIL~~ PRODUCTION FACILITIES ON THE DISTURBED AREA FOR THE DRILL PAD ~~AND [ ] TRUCK [ ] TRANSPORT THE PRODUCTION THROUGH A PIPELINE TO A TIE IN IN SECTION ____, T. ____, R.~~ V-Door oriented North.

2. LOCATION AND NATURAL SETTING (EXISTING ENVIRONMENTAL SITUATION).

(1) TOPOGRAPHY: [X] ROLLING HILLS [ ] DISSECTED TOPOGRAPHY [X] DESERT OR PLAINS [ ] STEEP CANYON SIDES [ ] NARROW CANYON FLOORS [ ] DEEP DRAINAGE IN AREA [ ] SURFACE WATER

(2) VEGETATION: [X] SAGEBRUSH [ ] PINION-JUNIPER [ ] PINE/FIR [ ] FARMLAND (CULTIVATED) [X] NATIVE GRASSES [ ] OTHER

(3) WILDLIFE: ☐ DEER ☐ ANTELOPE ☐ ELK ☐ BEAR ☒ SMALL MAMMAL ☒ BIRDS ☐ ENDANGERED SPECIES ☐ OTHER

(4) LAND USE: ☐ RECREATION ☒ LIVESTOCK GRAZING ☐ AGRICULTURE ☐ MINING ☐ INDUSTRIAL ☐ RESIDENTIAL ☒ OIL & GAS OPERATIONS

Indian Lands

REF: ~~BLM UMBRELLA EAR~~ BIA - Fort Duchesne
~~USFS EAR~~
~~OTHER ENVIRONMENTAL ANALYSIS~~

3. Effects on Environment by Proposed Action (potential impact)

1) EXHAUST EMISSIONS FROM THE DRILLING RIG POWER UNITS AND SUPPORT TRAFFIC ENGINES WOULD ADD MINOR POLLUTION TO THE ATMOSPHERE IN THE LOCAL VICINITY.

2) MINOR INDUCED AND ACCELERATED EROSION POTENTIAL DUE TO SURFACE DISTURBANCE AND SUPPORT TRAFFIC USE.

3) MINOR VISUAL IMPACTS FOR A SHORT TERM DUE TO OPERATIONAL EQUIPMENT AND SURFACE DISTURBANCE.

4) TEMPORARY DISTURBANCE OF WILDLIFE AND LIVESTOCK.

5) MINOR DISTRACTION FROM AESTHETICS FOR SHORT TERM.

6)

1) NOT APPROVING TH[illegible]POSED PERMIT -- THE OIL AND [illegible] LEASE GRANTS THE LESSEE EXCLUSIVE RIGHT TO DRILL FOR, MINE, EXTRACT, REMOVE AND DISPOSE OF ALL OIL AND GAS DEPOSITS.

2) DENY THE PROPOSED PERMIT AND SUGGEST AN ALTERNATE LOCATION TO MINIMIZE ENVIRONMENTAL IMPACTS. NO ALTERNATE LOCATION ON THIS LEASE WOULD JUSTIFY THIS ACTION.

3) LOCATION WAS MOVED ______ TO AVOID ______
☐ LARGE SIDEHILL CUTS ☐ NATURAL DRAINAGE ☐ OTHER ______

4) ______

5. Adverse Environmental Effects Which Cannot Be Avoided

1) MINOR AIR POLLUTION DUE TO EXHAUST EMISSIONS FROM RIG ENGINES AND SUPPORT TRAFFIC ENGINES.

2) MINOR INDUCED AND ACCELERATED EROSION POTENTIAL DUE TO SURFACE DISTURBANCE AND SUPPORT TRAFFIC USE.

3) MINOR AND TEMPORARY DISTURBANCE OF WILDLIFE.

4) TEMPORARY DISTURBANCE OF LIVESTOCK.

5) MINOR AND SHORT-TERM VISUAL IMPACTS.

6) ______

6. DETERMINATION:

(THIS REQUESTED ACTION (DOES) (DOES NOT) CONSTITUTE A MAJOR FEDERAL ACTION SIGNIFICANTLY AFFECTING THE ENVIRONMENT IN THE SENSE OF NEPA, SECTION 102(2) (C).

DATE INSPECTED 1/31/78

W P Martens

INSPECTOR James E Wilson

U. S. GEOLOGICAL SURVEY
CONSERVATION DIVISION - OIL & GAS OPERATIONS
SALT LAKE CITY DISTRICT

February 10, 1978

MEMO TO FILE:

Re: Belco Petroleum Company
Natural Buttes Unit 21-20
NE NE Sec. 20, T. 9S., R. 20E.
~~Grand~~ County, Utah
Uinta

Belco Petroleum Company informed this Dividion that the above well was spudded-in on February 9, 1978 at 3:00 p.m.

TWT is the drilling contractor and their Rig #6 is being used.

PATRICK L. DRISCOLL
CHIEF PETROLEUM ENGINEER
DIVISION OF OIL, GAS, & MINING

PLD/ksw

Form 9-330
(Rev. 5-63)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN DUPLICATE* (See instructions on reverse side)

Form approved.
Budget Bureau No. 42-R355.5.

WELL COMPLETION OR RECOMPLETION REPORT AND LOG*

5. LEASE DESIGNATION AND SERIAL NO.: UTAH 0144869

6. IF INDIAN, ALLOTTEE OR TRIBE NAME:

1a. TYPE OF WELL: OIL WELL ☐ GAS WELL XX DRY ☐ Other

b. TYPE OF COMPLETION: NEW WELL XX WORK OVER ☐ DEEPEN ☐ PLUG BACK ☐ DIFF. RESVR. ☐ Other

7. UNIT AGREEMENT NAME: NATURAL BUTTES UNIT

8. FARM OR LEASE NAME:

RECEIVED APR 28 1978 DIVISION OF OIL, GAS, & MINING

2. NAME OF OPERATOR: BELCO DEVELOPMENT CORPORATION

9. WELL NO.: 21-20B

3. ADDRESS OF OPERATOR: P. O. BOX 250, BIG PINEY, WYOMING 83113

10. FIELD AND POOL, OR WILDCAT: NBU - WASATCH

4. LOCATION OF WELL (*Report location clearly and in accordance with any State requirements*)*
At surface: 1037' FNL & 1033' FEL (NE NE)
At top prod. interval reported below: SAME
At total depth: SAME

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA: SEC 20, T9S, R20E

14. PERMIT NO.: 30359 | DATE ISSUED: 1/27/78

12. COUNTY OR PARISH: UINTAH | 13. STATE: UTAH

15. DATE SPUDDED	16. DATE T.D. REACHED	17. DATE COMPL. (*Ready to prod.*)	18. ELEVATIONS (DF, RKB, RT, GR, ETC.)*	19. ELEV. CASINGHEAD
2/9/78	3/3/78	4/5/78	4785' KB	4769'

20. TOTAL DEPTH, MD & TVD	21. PLUG, BACK T.D., MD & TVD	22. IF MULTIPLE COMPL., HOW MANY*	23. INTERVALS DRILLED BY	ROTARY TOOLS	CABLE TOOLS
7025'	6982'		→	ALL	

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*: 6068' to 6920' WASATCH

25. WAS DIRECTIONAL SURVEY MADE: NO

26. TYPE ELECTRIC AND OTHER LOGS RUN: DIL, CNL-FDC-GR

27. WAS WELL CORED: NO

28. CASING RECORD (*Report all strings set in well*)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
9-5/8"	36.0#	196'	12¼"	200 sx Class "G"	NONE
4½"	11.6#	7025'	7-7/8"	2100 sx 50-50 Pozmix	NONE

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
2-3/8"	6936'	

31. PERFORATION RECORD (*Interval, size and number*)

6092-94'	6592-94'
6111-13'	6907-09'
6118-20'	6914-16'
6128-30'	

32. ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
6092-6916'	82,317 gal MY-T-GEL III, 52,000# 100 mesh & 160,000# 20/40 sand.

33.* PRODUCTION

DATE FIRST PRODUCTION	PRODUCTION METHOD (*Flowing, gas lift, pumping—size and type of pump*)	WELL STATUS (*Producing or shut-in*)
4/5/78	FLOWING SI awaiting pipeline connection	SHUT IN

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
4/10/78	24	32/64"	→	--	5863	--	--

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
800	1350	→	--	5863	--	--

34. DISPOSITION OF GAS (*Sold, used for fuel, vented, etc.*)

TEST WITNESSED BY: AL MAXFIELD

35. LIST OF ATTACHMENTS

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records

SIGNED Robert Springman TITLE ENGINEERING TECHNICIAN DATE 4/24/78

*(See Instructions and Spaces for Additional Data on Reverse Side)

INSTRUCTIONS

General: This form is designed for submitting a complete and correct well completion report and log on all types of lands and leases to either a Federal agency or a State agency, or both, pursuant to applicable Federal and/or State laws and regulations. Any necessary special instructions concerning the use of this form and the number of copies to be submitted, particularly with regard to local, area, or regional procedures and practices, either are shown below or will be issued by, or may be obtained from, the local Federal and/or State office. See instructions on items 22 and 24, and 33, below regarding separate reports for separate completions.

If not filed prior to the time this summary record is submitted, copies of all currently available logs (drillers, geologists, sample and core analysis, all types electric, etc.), formation and pressure tests, and directional surveys, should be attached hereto, to the extent required by applicable Federal and/or State laws and regulations. All attachments should be listed on this form, see item 35.

Item 4: If there are no applicable State requirements, locations on Federal or Indian land should be described in accordance with Federal requirements. Consult local State or Federal office for specific instructions.

Item 18: Indicate which elevation is used as reference (where not otherwise shown) for depth measurements given in other spaces on this form and in any attachments.

Items 22 and 24: If this well is completed for separate production from more than one interval zone (multiple completion), so state in item 22, and in item 24 show the producing interval, or intervals, top(s), bottom(s) and name(s) (if any) for only the interval reported in item 33. Submit a separate report (page) on this form, adequately identified, for each additional interval to be separately produced, showing the additional data pertinent to such interval.

Item 29: *"Sacks Cement":* Attached supplemental records for this well should show the details of any multiple stage cementing and the location of the cementing tool.

Item 33: Submit a separate completion report on this form for each interval to be separately produced. (See instruction for items 22 and 24 above.)

37. SUMMARY OF POROUS ZONES:
SHOW ALL IMPORTANT ZONES OF POROSITY AND CONTENTS THEREOF; CORED INTERVALS; AND ALL DRILL-STEM TESTS, INCLUDING DEPTH INTERVAL TESTED, CUSHION USED, TIME TOOL OPEN, FLOWING AND SHUT-IN PRESSURES, AND RECOVERIES

FORMATION	TOP	BOTTOM	DESCRIPTION, CONTENTS, ETC.

38. GEOLOGIC MARKERS

NAME	TOP	
	MEAS. DEPTH	TRUE VERT. DEPTH
GREEN RIVER	1704'	+3081'
WASATCH	5210'	- 425
Chapita Wells	5774'	- 990
Buck Canyon	6224'	-1639

ederal Energy Regulatory Commission
25 North Capitol Street, N.E.
ashington, D.C. 20426

Docket No. UC 484-9B

FINAL DETERMINATION BY THE OIL AND GAS SUPERVISOR UNDER THE NATURAL GAS POLICY ACT OF 1978 (NGPA)

A final category determination is set forth below pursuant to the provisions of the NGPA for certain Federal lease gas as requested in application received on 3-28-79 and filed by Gas Producing Enterprises,Inc.

For the onshore:

Well Name and No.: NBU 21-20B

Sec., T. and R.: Sec. 20, T9S, R20E

API No.: 43-047-30359

Reservoir: Wasatch

Lease No.: U-0144869

County and State: Uintah, Utah

For the OCS:

Lease and Well No.:

Block:

API No:

Reservoir:

Nearby State:

Category determination requested: Section 102 (c)(1)(C)

Final category determination: Approved as requested ______ Negative determination X

Remarks: Application Well Correltes with Old Sun #2 Well and the Virgin Pressure in Well 21-20B Could be provided by the Lower Sands which are definitely new sands. Not enough convincing proof this is a new reservoir.

In accordance with the requirements of 18 CFR 274.104, the following information and reference materials will be submitted to the FERC with this final determination:*

1. List of participants including the applicant and all parties submitting comments on the application.

2. A statement on any matter opposed.

3. A copy of the application. Also, a copy of any other materials in the record used in the determination together with any information inconsistent (or possibly inconsistent) with the determination, which includes:

4. All materials required under 18 CFR 274, Subpart B, and all other record materials (and portions of record materials) used in the determination process are enclosed.

5. ~~An explanatory statement summarizing the basis for the determination is enclosed.~~

6. For a New Onshore Production Well determination involving 18 CFR 271.305(b) or (c), a finding as to the necessity of the well is enclosed.

A final jurisdictional agency determination is hereby made that the Federal lease natural gas referred to above does/does not qualify as natural gas produced from a ______ in accordance with the applicable provisions of the NGPA.

Any person may object to this final determination by filing a protest with the FERC within 15 days after this determination is published by the FERC in the Federal Register in accordance with 18 CFR Part 275.

Name: for C. J. Curtis

Title: Area Oil & Gas Supervisor
NRMA

Signature: R.M. Casey

Date: 4-28-80 Phone number: (307) 265-5550ext 5405 Address: P. O. Box 2859
Casper, WY 82602

*In the case of a negative determination, only a copy of the negative determination and a copy of Form FERC 121 will be forwarded to FERC. If the applicant or any aggrieved party so requests within 15 days of making such a determination, all information referenced in 1 through 6 will be forwarded within 20 days following the determination to the FERC in accordance with 18 CFR 274.104(b).

cc: Applicant
Purchaser(s)
NGPA File
Public Info. File
Lease File
~~Commentors~~
Co-lessees
New Reservoir
State File

RECEIVED
APR 30 1980
DIVISION OF
OIL, GAS & MINING

FORM CIG 881-2/68

COLORADO INTERSTATE GAS COMPANY

ONE-POINT BACK PRESSURE TEST FOR NATURAL GAS WELLS

COMPANY: BELCO PETROLEUM CORP.	LEASE: NATURAL BUTTES	WELL NUMBER: 21-20
FIELD: NATURAL BUTTES AREA	PRODUCING FORMATION: WASATCH SA	COUNTY UINTAH COUNTY

SECTION: 20	TOWNSHIP: 9S	RANGE: 20E	PIPELINE CONNECTION: COLORADO INTERSTATE GAS COMPANY		
CASING (O.D.):	WT./FT.:	I.D.:	SET AT:	PERF.:	TO:
TUBING (O.D.):	WT./FT.:	I.D.:	SET AT:	PERF.:	TO:
PAY FROM:	TO:	L: 7000 (estimated)	G(RAW GAS): .630	GL: 4410.000	de: 1.9950 (calculated)
PRODUCING THRU: TUBING	STATIC COLUMN: YES	PACKER (S) SET @:	G (SEPARATOR): .630	METER RUN SIZE: 2.067 " (FLANGE)	ATTRIBUTABLE ACREAGE:

DATE OF FLOW TEST: 9- 2-78 9- 5-78

OBSERVED DATA

ORIFICE SIZE INCHES	METER DIFFERENTIAL RANGE	METER PRESSURE	DIFFERENTIAL ROOTS	FLOWING TEMPERATURE t	CASING WELLHEAD PRESSURE p.s.i.g.	CASING WELLHEAD PRESSURE p.s.i.a.	TUBING WELLHEAD PRESSURE p.s.i.g.	TUBING WELLHEAD PRESSURE p.s.i.a.
1.250	100	504.0	4.15	82	770.0	783.0	590.0	603.0

RATE OF FLOW CALCULATIONS

24 HOUR COEFFICIENT	METER PRESSURE p.s.i.a.	hw	$P_m h_w$	EXTENSION $\sqrt{P_m h_w}$	GRAVITY FACTOR Fg	FLOWING TEMP. FACTOR Ft	DEVIATION FACTOR Fpv	RATE OF FLOW R MCFD
8329.0	517.0	17.22	8904.291	94.363	1.260	.9795	1.0431	1011.80

DATE OF SHUT-IN TEST: 9- 8-78

PRESSURE CALCULATIONS

SHUT-IN PRESSURE: CASING: 1050.0 p.s.i.g.	TUBING: 823.0 p.s.i.g.	BAR. 14.4 p.s.i. 13.000	P_c 1063.0 p.s.i.a.	P_c^2 1129969.0

P_w p.s.i.a.	P_w^2	P_r	T_r	Z
783.0	613089.0			

POTENTIAL CALCULATIONS

(1) $\frac{P_c^2 - P_a^2}{P_c^2 - P_w^2} =$ 2.1861

(2) $\left[\frac{P_c^2 - P_a^2}{P_c^2 - P_w^2}\right]^n =$ 1.6291

(3) $R\left[\frac{P_c^2 - P_a^2}{P_c^2 - P_w^2}\right]^n =$ 1648

CALCULATED WELLHEAD OPEN FLOW 1648 MCFD @ 14.65	BASIS OF ALLOCATION:	SLOPE n: .624 (Average)
APPROVED BY COMMISSION:	CONDUCTED BY:	CHECKED BY:

I, ______________________, BEING FIRST DULY SWORN ON OATH, STATE THAT I AM FAMILIAR WITH FACTS AND FIGURES SET FORTH IN THIS REPORT, AND THAT THE REPORT IS TRUE AND CORRECT.

______________________ SIGNATURE AND TITLE OF AFFIANT

______________________ COMPANY

SUBSCRIBED AND SWORN TO BEFORE ME THIS ____________ DAY OF ______________________, 19 ____

MY COMMISSION EXPIRES

______________________ NOTARY PUBLIC

FORM CIG 4896-7/73

COLORADO INTERSTATE GAS COMPANY

WELL TEST DATA FORM

STATE COPY

FIELD CODE	FIELD NAME	OPERATOR CODE	OPERATOR NAME	WELL NAME
[illegible]-01-11	NATURAL BUTTES	[illegible]	BELCO PETROLEUM CORP.	NATURAL BUTTES 21-20

CODE	LOCATION SECT.	TWNSHP/BLK	RGE/SUR.	PANHANDLE/REDCAVE SEQ. NUMBER	K-FACTOR	FORMATION		
[illegible]	20	9S	20E			WASATCH SA	FLOW TEST	1

FLOW TEST

WELL ON (OPEN) MO.	DAY	YR.	DATE (COMP.) MO.	DAY	YR.	ORIFICE SIZE	METER RUN SIZE	COEFFICIENT	GRAVITY (SEP.)	METER DIFF. RANGE	METER PRESSURE	DIFFERENTIAL ROOTS	METER TEMP.	WELL HEAD TEMP.	FLOWING TBG/CSG PRESSURE	STATIC TSG/CSG PRESSURE	FLOWING STRING TUBING	CASING
11 - 12	13 - 14	15 - 16	17 - 18	19 - 20	21 - 22	23 — 27	28 — 32	33 — 38	39 — 42	43 — 45	46 — 51	52 — 55	56 — 58	59 — 61	62 — 67	68 — 73	74	75
X X	X X	X X	X X	X X	X X	X X X X X	X X X X X	X X X X X X	X X X X	X X X	X X X X X X	X X X X	X X X	X X X	X X X X X X	X X X X X X	X	X
11	27	80	10	14	80	00 500	2 067			100	00745 0	09 50	088		00932	001034 0	X	

SHUT-IN TEST

WELL-OFF (SHUT-IN) MO.	DAY	YR.	PRESSURE TAKEN MO.	DAY	DATE YR.	CASING PRESSURE (PSIG)	TUBING PRESSURE (PSIG)	SLOPE	EFFECTIVE DIAMETER	EFFECTIVE LENGTH	GRAVITY (RAW GAS)	EST CSG PRESS	EST TBG PRESS
11-12	13-14	15-16	17-18	19-20	21-22	23 — 28	29 — 34	35 — 38	39 — 44	45 — 49	50 — 53	54	55
X X	X X	X X	X X	X X	X X	X X X X X X	X X X X X X	X X X X	X X X X X X	X X X X X	X X X X	E	E
09	02	80	09	06	80	01134 0	011400	624	1 9950	7000			

TO THE BEST OF MY KNOWLEDGE THE ABOVE DATA IS CORRECT.

CIG: L Brown

OPERATOR:

COMMISSION:

73000 00500

REMARKS: the diff. in 15 to 20 hours will drop from 9.8 to 0, blow well and will do same again. This well has intermitting production. The well was blown 3 hours before these pressures was taken

FORM CIG 896–7/73

COLORADO INTERSTATE GAS COMPANY

STATE COPY

WELL TEST DATA FORM

FIELD CODE	FIELD NAME	OPERATOR CODE	OPERATOR NAME	WELL NAME
[illegible]	NATURAL BUTTES, UT	[illegible]	BELCO DEVELOPMENT CORP	NATURAL BUTTES 21-[illegible]

WELL CODE 3 — 7	SECT.	LOCATION TWNSHP/BLK	RGE/SUR.	PANHANDLE/REDCAVE SEQ. NUMBER	K-FACTOR	FORMATION	
[illegible]		[illegible]	[illegible]			WASATCH SA	FLOW TEST

FLOW TEST

WELL ON (OPEN) MO.	DAY	YR.	DATE (COMP.) MO.	DAY	YR.	ORIFICE SIZE		METER RUN SIZE		COEFFICIENT		GRAVITY (SEP.)		METER DIFF. RANGE	METER PRESSURE		DIFFERENTIAL ROOTS		METER TEMP.	WELL HEAD TEMP.	FLOWING TBG/CSG PRESSURE		STATIC TSG/CSG PRESSURE		FLOWING STRING TUBING	CASING
11 - 12	13 - 14	15 - 16	17 - 18	19 - 20	21 - 22	23 — 27		28 — 32		33 — 38		39 — 42		43 — 45	46 — 51		52 — 55		56 — 58	59 — 61	62 — 67		68 — 73		74	75
XX	XX	XX	XX	XX	XX	XX	XXX	XX	XXX	XXXXX	X	X	XXX	XXX	XXXXX	X	XX	XX	XXX	XXX	XXXXX	X	XXXXX	X	X	X
[illegible]	[illegible]	71						3	067			0	624	100												

SHUT-IN TEST

WELL-OFF (SHUT-IN) MO.	DAY	YR.	PRESSURE TAKEN DATE MO.	DAY	YR.	CASING PRESSURE (PSIG)		TUBING PRESSURE (PSIG)		SLOPE		EFFECTIVE DIAMETER		EFFECTIVE LENGTH	GRAVITY (RAW GAS)		EST CSG PRESS	EST TBG PRESS
11 - 12	13 - 14	15 - 16	17 - 18	19 - 20	21 - 22	23 — 28		29 — 34		35 — 38		39 — 44		45 — 49	50 — 53		54	55
XX	XX	XX	XX	XX	XX	XXXXX	X	XXXXX	X	X	XXX	XX	XXXX	XXXXX	X	XXX	E	E
											435	1	995[illegible]	6504				

TO THE BEST OF MY KNOWLEDGE THE ABOVE DATA IS CORRECT.

CIG: [illegible]

OPERATOR: [illegible]

COMMISSION: ______________

METER STAMP: 70000 00750

REMARKS: CIG shut in well due to [illegible] [illegible], [illegible] messed up our equipment

FORM CIG 4896-7/73

COLORADO INTERSTATE GAS COMPANY

WELL TEST DATA FORM

STATE COPY

FIELD CODE	FIELD NAME	OPERATOR CODE	OPERATOR NAME	WELL NAME
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

CODE	SECT.	LOCATION TWNSHP/BLK	RGE/SUR.	PANHANDLE/REDCAVE SEQ. NUMBER	PANHANDLE/REDCAVE K-FACTOR	FORMATION
[illegible]	[illegible]	[illegible]	[illegible]			[illegible]

FLOW TEST

WELL ON (OPEN) MO.	DAY	YR.	DATE (COMP.) MO.	DAY	YR.	ORIFICE SIZE	METER RUN SIZE	COEFFICIENT	GRAVITY (SEP.)	METER DIFF. RANGE	METER PRESSURE	DIFFERENTIAL ROOTS	METER TEMP.	WELL HEAD TEMP.	FLOWING TBG/CSG PRESSURE	STATIC TSG/CSG PRESSURE	FLOWING STRING TUBING	CASING
11 - 12	13 - 14	15 - 16	17 - 18	19 - 20	21 - 22	23 — 27	28 — 32	33 — 38	39 — 42	43 — 45	46 — 51	52 — 55	56 — 58	59 — 61	62 — 67	68 — 73	74	75
X X	X X	X X	X X	X X	X X	X X X X X	X X X X X	X X X X X X	X X X X	X X X	X X X X X X	X X X X	X X X	X X X	X X X X X X	X X X X X X	X	X
[illegible]	[illegible]	[illegible]	07	[illegible]	83	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]		[illegible]	[illegible]	X	

SHUT-IN TEST

WELL-OFF (SHUT-IN) MO.	DAY	YR.	PRESSURE TAKEN DATE MO.	DAY	YR.	CASING PRESSURE (PSIG)	TUBING PRESSURE (PSIG)	SLOPE	EFFECTIVE DIAMETER	EFFECTIVE LENGTH	GRAVITY (RAW GAS)	EST CSG PRESS	EST TBG PRESS
11-12	13-14	15-16	17-18	19-20	21-22	23 — 28	29 — 34	35 — 38	39 — 44	45 — 49	50 — 53	54	55
X X	X X	X X	X X	X X	X X	X X X X X X	X X X X X X	X X X X	X X X X X X	X X X X X	X X X X	E	E

TO THE BEST OF MY KNOWLEDGE THE ABOVE DATA IS CORRECT.

CIG: [illegible]

OPERATOR: [illegible] Watkins

COMMISSION:

23000 00750

REMARKS:

FORM CIG 4896-7/73

COLORADO INTERSTATE GAS COMPANY

STATE COPY

WELL TEST DATA FORM

FIELD CODE	FIELD NAME	OPERATOR CODE	OPERATOR NAME	WELL NAME
560-01-11	NATURAL BUTTES, UT	0828	BELCO DEVELOPMENT CORP	NATURAL BUTTES 21-20

WELL CODE 3—7	SECT.	LOCATION TWNSHP/BLK	RGE/SUR.	PANHANDLE/REDCAVE SEQ. NUMBER	K-FACTOR	FORMATION
73000	20	9S	20E			WASATCH SA FLOW TEST

FLOW TEST

WELL ON (OPEN) MO.	DAY	YR.	DATE (COMP.) MO.	DAY	YR.	ORIFICE SIZE	METER RUN SIZE	COEFFICIENT	GRAVITY (SEP.)	METER DIFF. RANGE	METER PRESSURE	DIFFERENTIAL ROOTS	METER TEMP.	WELL HEAD TEMP.	FLOWING TBG/CSG PRESSURE	STATIC TSG/CSG PRESSURE	FLOWING STRING TUBING	CASING
11 - 12	13 - 14	15 - 16	17 - 18	19 - 20	21 - 22	23 — 27	28 — 32	33 — 38	39 — 42	43 — 45	46 — 51	52 — 55	56 — 58	59 — 61	62 — 67	68 — 73	74	75
XX	XX	XX	XX	XX	XX	XX XXX	XX XXX	XXXXX X	X XXX	XXX	XXXXX X	XX XX	XXX	XXX	XXXXX X	XXXXX X	X	X
02	07	84	02	14	84	00 750	2 067	02779 0	0 627	100	00580 0		088		00583 0	00680 0	X	

SHUT-IN TEST

WELL-OFF (SHUT-IN) MO.	DAY	YR.	PRESSURE TAKEN MO.	DAY	YR.	CASING PRESSURE (PSIG)	TUBING PRESSURE (PSIG)	SLOPE	EFFECTIVE DIAMETER	EFFECTIVE LENGTH	GRAVITY (RAW GAS)	EST CSG PRESS	EST TBG PRESS
11-12	13-14	15-16	17-18	19-20	21-22	23 — 28	29 — 34	35 — 38	39 — 44	45 — 49	50 — 53	54	55
XX	XX	XX	XX	XX	XX	XXXXX X	XXXXX X	X XXX	XX XXXX	XXXXX	X XXX	E	E
02	20	84	02	23	84	00740 0	00735 0	835	1 9950	6504	0 627		

TO THE BEST OF MY KNOWLEDGE THE ABOVE DATA IS CORRECT.

CIG: [illegible]

OPERATOR:

COMMISSION:

METER STAMP: 73000 00750

REMARKS: [illegible] give diff.

FORM CIG 4896-7/73

COLORADO INTERSTATE GAS COMPANY

WELL TEST DATA FORM

STATE COPY

FIELD CODE	FIELD NAME	OPERATOR CODE	OPERATOR NAME	WELL NAME
[illegible]	[illegible]		[illegible]	[illegible]

WELL CODE 3 ——— 7	LOCATION SECT.	TWNSHP/BLK	RGE/SUR.	PANHANDLE/REDCAVE SEQ. NUMBER	K-FACTOR	FORMATION		
						[illegible]	[illegible]	

FLOW TEST

WELL ON (OPEN) MO.	DAY	YR.	DATE (COMP.) MO.	DAY	YR.	ORIFICE SIZE	METER RUN SIZE	COEFFICIENT	GRAVITY (SEP.)	METER DIFF. RANGE	METER PRESSURE	DIFFERENTIAL ROOTS	METER TEMP.	WELL HEAD TEMP.	FLOWING TBG/CSG PRESSURE	STATIC TSG/CSG PRESSURE	FLOWING STRING TUBING	CASING
11 - 12	13 - 14	15 - 16	17 - 18	19 - 20	21 - 22	23 — 27	28 — 32	33 — 38	39 — 42	43 — 45	46 — 51	52 — 55	56 — 58	59 — 61	62 — 67	68 — 73	74	75
X X	X X	X X	X X	X X	X X	X X ¦ X X X	X X ¦ X X X	X X X X X ¦ X	X ¦ X X X	X X X	X X X X X ¦ X	X X ¦ X X	X X X	X X X	X X X X X ¦ X	X X X X X ¦ X	X	X
12	31	82	09	07	82	00 ¦ 575		02779 ¦ 0	0 ¦ 637		00600	01 ¦ 50	8[illegible]		[illegible]	00 ¦ 820	X	

SHUT-IN TEST

WELL-OFF (SHUT-IN) MO.	DAY	YR.	PRESSURE TAKEN MO.	DAY	DATE YR.	CASING PRESSURE (PSIG)	TUBING PRESSURE (PSIG)	SLOPE	EFFECTIVE DIAMETER	EFFECTIVE LENGTH	GRAVITY (RAW GAS)	EST CSG PRESS	EST TBG PRESS
11-12	13-14	15-16	17-18	19-20	21-22	23 — 28	29 — 34	35 — 38	39 — 44	45 — 49	50 — 53	54	55
X X	X X	X X	X X	X X	X X	X X X X X ¦ X	X X X X X ¦ X	X ¦ X X X	X X ¦ X X X X	X X X X X	X ¦ X X X	E	E
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]						

TO THE BEST OF MY KNOWLEDGE THE ABOVE DATA IS CORRECT.

CIG: [signature]

OPERATOR: [signature]

COMMISSION:

METER STAMP

23000 00750

REMARKS: I. P. WELL ESTIMATED AFF ACCEPTED

FORM CIG 4896-7/73

COLORADO INTERSTATE GAS COMPANY

WELL TEST DATA FORM

STATE COPY

FIELD CODE	FIELD NAME	OPERATOR CODE	OPERATOR NAME	WELL NAME
560-01-11	NATURAL BUTTES	0828	BELCO PETROLEUM CORP.	NATURAL BUTTES 21-20

WELL CODE 3—7	SECT.	TWNSHP/BLK	RGE/SUR.	SEQ. NUMBER	K-FACTOR	FORMATION
73000	20	9S	20E			WASATCH SA FLOW TEST

FLOW TEST

WELL ON (OPEN) MO.	DAY	YR.	DATE (COMP.) MO.	DAY	YR.	ORIFICE SIZE	METER RUN SIZE	COEFFICIENT	GRAVITY (SEP.)	METER DIFF. RANGE	METER PRESSURE	DIFFERENTIAL ROOTS	METER TEMP.	WELL HEAD TEMP.	FLOWING TBG/CSG PRESSURE	STATIC TSG/CSG PRESSURE	FLOWING STRING TUBING	CASING
11 - 12	13 - 14	15 - 16	17 - 18	19 - 20	21 - 22	23 — 27	28 — 32	33 — 38	39 — 42	43 — 45	46 — 51	52 — 55	56 — 58	59 — 61	62 — 67	68 — 73	74	75
X X	X X	X X	X X	X X	X X	X X X X X	X X X X X	X X X X X X	X X X X	X X X	X X X X X X	X X X X	X X X	X X X	X X X X X X	X X X X X X	X	X
							2 067			100								

SHUT-IN TEST

WELL-OFF (SHUT-IN) MO.	DAY	YR.	PRESSURE TAKEN DATE MO.	DAY	YR.	CASING PRESSURE (PSIG)	TUBING PRESSURE (PSIG)	SLOPE	EFFECTIVE DIAMETER	EFFECTIVE LENGTH	GRAVITY (RAW GAS)	EST CSG PRESS	EST TBG PRESS
11-12	13-14	15-16	17-18	19-20	21-22	23 — 28	29 — 34	35 — 38	39 — 44	45 — 49	50 — 53	54	55
X X	X X	X X	X X	X X	X X	X X X X X X	X X X X X X	X X X X	X X X X X X	X X X X X	X X X X	E	E
06	13	81	06	16	81	008050	006700	627	1 9950	7000			

TO THE BEST OF MY KNOWLEDGE THE ABOVE DATA IS CORRECT.

CIG:

OPERATOR:

COMMISSION:

METER STAMP: 73000 00750

REMARKS: Two well test
Producing gradually

BELCO DEVELOPMENT CORPORATION
DAILY DRILLING REPORT
FRIDAY, JANUARY 29,1982

VERNAL DISTRICT

DEVELOPMENT WELLS

~~EMCU 3-3 (NFWC-G)~~
~~Wildcat~~
~~Garfield County, Co.~~
~~TD 7310' Morrison~~
~~Chandler Rig #7~~
~~Belco WI 9-375%~~

6806'(614') 19. Drilling, Morrison.
Drld 614' in 17¼ hrs. Dev: 6404'-5° 6615'-5¼°.
Flare 15'- 5 sec. 6615'-D. SILT
Bit #6,7 7/8",FP-51,Jet open,614' in 17¼ hrs.
Air Press: 190#, Wt.3, RPM-90
Mud Prop: Dusting, SCFM 2750
TIH & blow hole dry-3 hrs. Survey-2 hrs.
Shut down to let helicopter on location & PU injured people- 1¼ hrs.
AFE (csg pt) $446,000
CUM COST $445,068

NDC 60-29 (DW-GAS)
North Duck Creek
Uintah County,Utah
TD 7545' Wasatch
AllWestern Rig #3
Belco WI 0%

249'(0') RU, Uintah.
AFE (csg pt) $333,000
CUM COST $ 74,141

RECEIVED
MAR 22 1982
DIVISION OF
OIL, GAS & MINING

OUTSIDE OPERATED

LISBON UNIT B-94
Lisbon Unit Field
San Juan County,Utah
Loffland Bros Rig #5
Union Oil Company
TD 9200' Mississippian
Belco WI 15.04722%

1-28-82
9150'(0') 42. PU BHA.
Mud Prop: MW-10.3, VIS-54, WL-7.2
Finished displacing diesel. Circ & Cond mud while working stuck DP. RU Brand X and run freepoint with collars @8807', 25% free and 100% free @8777'. Backed off @8777', leaving fish in hole. Chained and strapped out of hole in 6 hrs. Rec'd 8 DCs,X-over,and DP. Laid down shot collar, PU fishing assembly,inc.

WORKOVERS

NBU 21-20B (DW-GAS)
Natural Buttes
Uintah County,Utah
PBTD 6982' Wasatch
Utah Rental
Belco WI 100%

Sec 20, 9S20E

Report # 3
TIH w/2 3/8"tbg & Howco 4½ BP-Set @6200', Set 1 sack sand,land tbg @6111. Remove BOP, Install well head. Swab 30 min,Rec 12 BW, Well kicked off, Flowed to pit 2½ hrs. blowing med vpr, SI well overnight. SDFN.
This A.M. SI, TP-850, CP-900

TUBING DETAIL:

194 Jts 2 3/8"Tbg	6109.20
Howco Retreaving head	1.80
Set @	6111.00

CUM COST $6,891

Form 3160-5
(November 1983)
(Formerly 9-331)

UN[illegible] STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

SUBMIT IN TRIPL[illegible]A (Other instructions on [illegible] verse side)

Form approved.
Budget Bureau No. 1004-0135
Expires August 31, 1985

SUNDRY NOTICES AND REPORTS ON WELLS

(Do not use this form for proposals to drill or to deepen or plug back to a different reservoir. Use "APPLICATION FOR PERMIT—" for such proposals.)

RECEIVED
APR 29 1985
DIVISION OF OIL GAS & MINING

1. OIL WELL ☐ GAS WELL ☐ OTHER

2. NAME OF OPERATOR
BELCO DEVELOPMENT CORPORATION

3. ADDRESS OF OPERATOR
P.O. BOX X, VERNAL, UTAH 84078

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements. See also space 17 below.)
At surface
1037' FNL & 1033' FEL NE/NE

5. LEASE DESIGNATION AND SERIAL NO.
U-0144869

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

7. UNIT AGREEMENT NAME
Natural Buttes

8. FARM OR LEASE NAME
21-20B

9. WELL NO.
Natural Buttes

10. FIELD AND POOL, OR WILDCAT

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20, T9S, R20E

14. PERMIT NO.
43-047-30359

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
4785' KB

12. COUNTY OR PARISH
Uintah

13. STATE
Utah

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other)			☐
(Other)			☐				

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

This is to request that NTL 2B pit approval be extended to include 3 pits at this location. The use of the 3 pits are as follows:

1. The pit near the tank is to drain produced water from the tank.
2. The pit farther away is used to blow down the well.
3. The pit near the dehydrator is for CIG to dump their fluids.

Possibly Pits 1 & 2 could be done with Pit #2. However, the expense to cover up this pit or connect the two together would be $500-$1500. Since there is no safety hazard and the location is remote and the well is marginal it is requested that the pits be allowed as they are constructed.

18. I hereby certify that the foregoing is true and correct

SIGNED J Ball TITLE District Engineer DATE April 26, 1985

(This space for Federal or State office use)

APPROVED BY ____ TITLE ____ DATE ____
CONDITIONS OF APPROVAL, IF ANY:

*See Instructions on Reverse Side

Form 3160-5
(November 1983)
(Formerly 9-331)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

SUBMIT IN TRIPLICATE
(Other instructions on reverse side)

102330

Budget Bureau No. 1004-0135
Expires August 31, 1985

5. LEASE DESIGNATION AND SERIAL NO.
U-0144869

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

SUNDRY NOTICES AND REPORTS ON WELLS

(Do not use this form for proposals to drill or to deepen or plug back to a different reservoir. Use "APPLICATION FOR PERMIT—" for such proposals.)

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME
NATURAL BUTTES

2. NAME OF OPERATOR
BELCO DEVELOPMENT CORPORATION

8. FARM OR LEASE NAME
NATURAL BUTTES

3. ADDRESS OF OPERATOR
P.O. BOX 1815 VERNAL, UTAH 84078

9. WELL NO.
NBU 21-20

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface

NE NE

10. FIELD AND POOL, OR WILDCAT
Natural Buttes

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec 20, T9S, R20E

14. PERMIT NO.
43-047- 30359

15. ELEVATIONS (Show whether DF, RT, GR, etc.)

12. COUNTY OR PARISH
UINTAH

13. STATE
UTAH

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:

TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐
REPAIR WELL	☐	CHANGE PLANS	☐
(Other) RESUMPTION OF PRODUCTION			☐

SUBSEQUENT REPORT OF:

WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
(Other)			☐

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

THIS IS TO ADVISE YOU THAT THE ABOVE MENTIONED WELL HAS BEEN RETURNED TO PRODUCTION AFTER BEING SI FOR 90 OR MORE DAYS. ORAL NOTICE WAS CALLED IN TO THE B.L.M. FRIDAY OCT. 17, 1986. RESUMPTION OF PRODUCTION BEGAN OCT. 12, 1986.

RECEIVED
OCT [illegible]
DIVISION OF
OIL, GAS & MINING

18. I hereby certify that the foregoing is true and correct

SIGNED [signature] TITLE DISTRICT SUPERINTENDENT DATE 10-20-86

(This space for Federal or State office use)

APPROVED BY ____________ TITLE ____________ DATE ____________
CONDITIONS OF APPROVAL, IF ANY:

*See Instructions on Reverse Side

Form 3160-5
(November 1983)
(Formerly 9-331)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

SUBMIT IN TRIPLICATE
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 1004-0135
Expires August 31, 1985

SUNDRY NOTICES AND REPORTS ON WELLS

(Do not use this form for proposals to drill or to deepen or plug back to a different reservoir. Use "APPLICATION FOR PERMIT—" for such proposals.)

1. OIL WELL ☐ GAS WELL ☒ OTHER

2. NAME OF OPERATOR
BELCO DEVELOPMENT CORPORATION

3. ADDRESS OF OPERATOR
P.O. BOX 1815, VERNAL, UTAH 84078

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface

5. LEASE DESIGNATION AND SERIAL NO.

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

7. UNIT AGREEMENT NAME
NATURAL BUTTES UNIT

8. FARM OR LEASE NAME

9. WELL NO.

10. FIELD AND POOL, OR WILDCAT

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA

12. COUNTY OR PARISH | 13. STATE

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)

16. **Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data**

NOTICE OF INTENTION TO:

TEST WATER SHUT-OFF ☐ PULL OR ALTER CASING ☐
FRACTURE TREAT ☐ MULTIPLE COMPLETE ☐
SHOOT OR ACIDIZE ☐ ABANDON* ☐
REPAIR WELL ☐ CHANGE PLANS ☐
(Other)

SUBSEQUENT REPORT OF:

WATER SHUT-OFF ☐ REPAIRING WELL ☐
FRACTURE TREATMENT ☐ ALTERING CASING ☐
SHOOTING OR ACIDIZING ☐ ABANDONMENT* ☐
(Other)
(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

THE WELLS LISTED BELOW WERE TURNED BACK TO PRODUCTION ON 11-10-86, SOME OF THESE WELLS HAVE BEEN SI LONGER THAN 90 DAYS.

NBU 1-7 B	NBU 26-13B	NBU 56-11B	NBU 216-35
NBU 2-15B	NBU 27-1 B	NBU 57-12B	NBU 217-2
NBU 3-2 B	NBU 28-4 B	NBU 58-23B	
NBU 4-35B	NBU 30-18B	NBU 62-35B	
NBU 5-36B	NBU 33-17B	NBU 63-12B	
NBU 7-9 B	NBU 34-17B	NBU 64-24B	
NBU 8-20B	NBU 35-8 B	NBU 65-25B	
NBU 10-29B	NBU 36-7 B	NBU 67-30B	
NBU 11-14B	NBU 37-13B	NBU 71-26B	
NBU 12-23B	NBU 42-35B	NBU 200-7	
NBU 13-8 B	NBU 43-36B	NBU 202-3	
NBU 15-29B	NBU 47-27B	NBU 205-8	
NBU 16-6 B	NBU 48-29B	NBU 206-9	
NBU 17-18B	NBU 49-12B	NBU 207-4	
NBU 19-21B	NBU 52-1 B	NBU 210-24	
NBU 21-20B 9520E	NBU 53-3 B	NBU 211-20	
NBU 23-19B	NBU 54-2 B	NBU 212-19	
NBU 25-20B	NBU 55-10B	NBU 213-36	

RECEIVED
NOV 17 1986
DIVISION OF
OIL, GAS & MINING

18. I hereby certify that the foregoing is true and correct

SIGNED J. Ball TITLE Dist. Superintendent DATE 11-14-86

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______ DATE ______
CONDITIONS OF APPROVAL, IF ANY:

***See Instructions on Reverse Side**

Title 18 U.S.C. Section 1001, makes it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

Form 3160-5
(November 1983)
(Formerly 9-331)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

Budget Bureau No. 1004-0135
Expires August 31, 1985

121077

SUNDRY NOTICES AND REPORTS ON WELLS

(Do not use this form for proposals to drill or to deepen or plug back to a different reservoir. Use "APPLICATION FOR PERMIT—" for such proposals.)

5. LEASE DESIGNATION AND SERIAL NO.: U-0144869

6. IF INDIAN, ALLOTTEE OR TRIBE NAME:

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME: Natural Buttes Unit

2. NAME OF OPERATOR: BELCO DEVELOPMENT CORPORATION

8. FARM OR LEASE NAME:

3. ADDRESS OF OPERATOR: P. O. Box 1815, Vernal, Utah 84078

9. WELL NO.: 21-20B

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface

1037' FNL & 1033' FEL (NE/NE)

10. FIELD AND POOL, OR WILDCAT: NBU Wasatch

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA: Sec 20, T9S, R20E

14. PERMIT NO.: 43-047-30359

15. ELEVATIONS (Show whether DF, RT, GR, etc.): 4785' KB

12. COUNTY OR PARISH: Uintah

13. STATE: Utah

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:

TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐
REPAIR WELL	☐	CHANGE PLANS	☐
(Other)			

SUBSEQUENT REPORT OF:

WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
(Other)			

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

This well was turned back to production on 11-10-86

RECEIVED
DEC 05 1986
DIVISION OF
OIL, GAS & MINING

18. I hereby certify that the foregoing is true and correct

SIGNED JaBell TITLE District Superintendent DATE 12-02-86

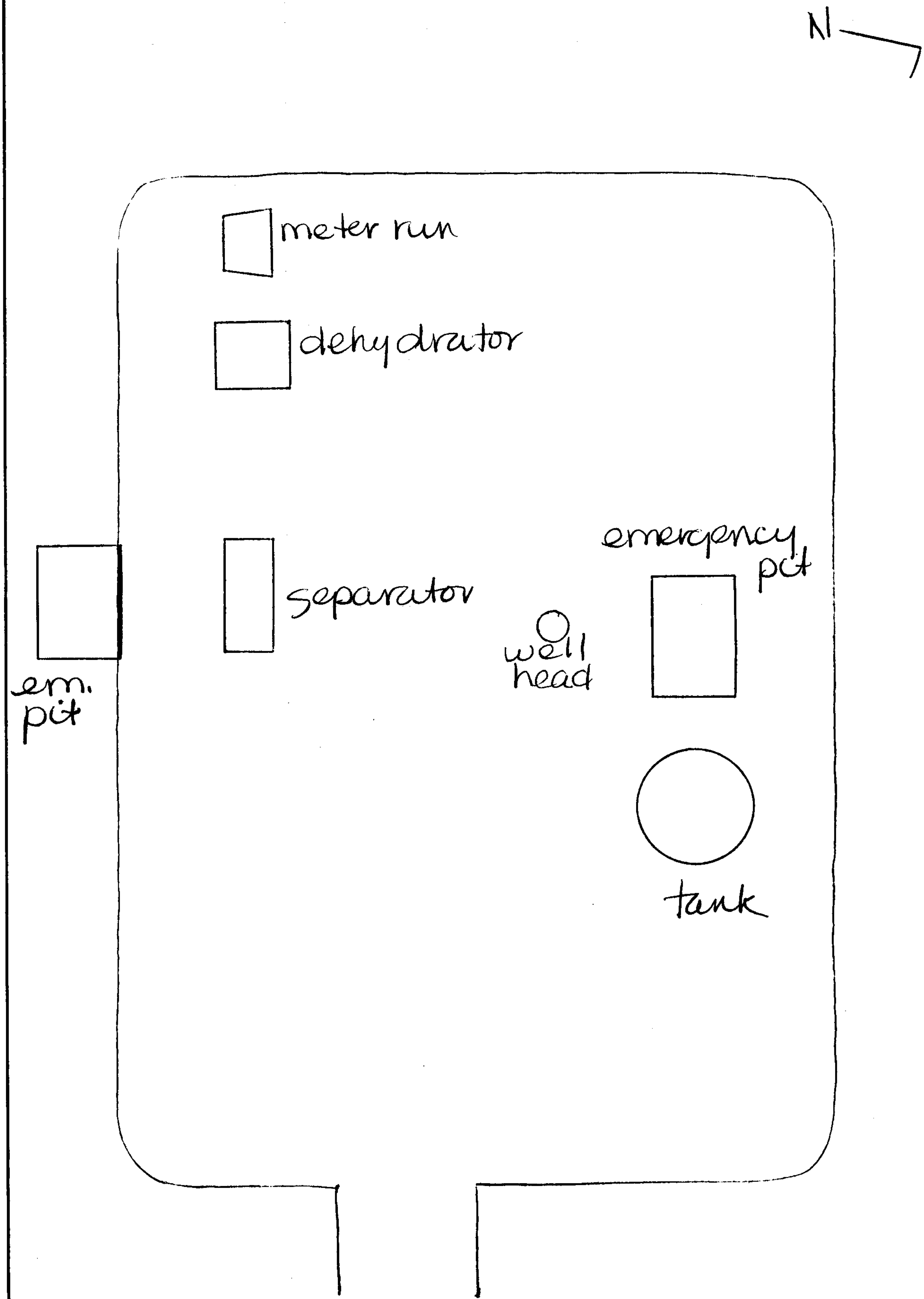
(This space for Federal or State office use)

APPROVED BY ____ TITLE ____ DATE ____
CONDITIONS OF APPROVAL, IF ANY:

*See Instructions on Reverse Side

Title 18 U.S.C. Section 1001, makes it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

NBU 21-20B Sec 20, T9S, R20E [signature] 1/9/89



Form 3160-5
(November 1983)
(Formerly 9-331)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

Budget Bureau No. 1004-0135
Expires August 31, 1985

SUNDRY NOTICES AND REPORTS ON WELLS

(Do not use this form for proposals to drill or to deepen or plug back to a different reservoir. Use "APPLICATION FOR PERMIT—" for such proposals.)

RECEIVED
NOV 08 1989
DIVISION OF
OIL, GAS & MINING

5. LEASE DESIGNATION AND SERIAL NO.
U 0144869

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

1. OIL WELL [ ] GAS WELL [X] OTHER

7. UNIT AGREEMENT NAME
NATURAL BUTTES UNIT

2. NAME OF OPERATOR
ENRON OIL & GAS COMPANY

8. FARM OR LEASE NAME

3. ADDRESS OF OPERATOR
P. O. BOX 1815 VERNAL, UTAH 84078

9. WELL NO.
21-20B

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1037' FNl & 1033' FEL (NE/NE)

10. FIELD AND POOL, OR WILDCAT
NBU WASATCH

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
SEC 20, T9S, R20E

14. PERMIT NO.
43 047 30359

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
4785' KB

12. COUNTY OR PARISH
UINTAH

13. STATE
UTAH

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:

TEST WATER SHUT-OFF	[ ]	PULL OR ALTER CASING	[ ]
FRACTURE TREAT	[ ]	MULTIPLE COMPLETE	[ ]
SHOOT OR ACIDIZE	[ ]	ABANDON*	[ ]
REPAIR WELL	[ ]	CHANGE PLANS	[ ]
(Other)			

SUBSEQUENT REPORT OF:

WATER SHUT-OFF	[ ]	REPAIRING WELL	[ ]
FRACTURE TREATMENT	[ ]	ALTERING CASING	[ ]
SHOOTING OR ACIDIZING	[ ]	ABANDONMENT*	[ ]
(Other)			

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

THIS WELL WAS TURNED BACK TO PRODUCTION 11-5-89 AFTER BEING SHUT IN OVER NINETY DAYS.

OIL AND GAS	
DRN	RJF
JRB	GLH
DTS	SLS

1. TAS
2. MICROFILM
3. FILE

18. I hereby certify that the foregoing is true and correct

SIGNED Linda L. Wall TITLE SR. ADMIN. CLERK DATE 11-9-89

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______ DATE ______
CONDITIONS OF APPROVAL, IF ANY:

*See Instructions on Reverse Side

Title 18 U.S.C. Section 1001, makes it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

(Formerly 9-331) DEPARTMENT OF THE INTERIOR

BUREAU OF LAND MANAGEMENT

5. LEASE DESIGNATION AND SERIAL NO.
U-0144869

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

SUNDRY NOTICES AND REPORTS ON WELLS

(Do not use this form for proposals to drill or to deepen or plug back to a different reservoir. Use "APPLICATION FOR PERMIT—" for such proposals.)

RECEIVED
MAR 27 1990
DIVISION OF
OIL GAS & MINING

1. OIL WELL ☐ GAS WELL ☒ XX OTHER

7. UNIT AGREEMENT NAME
Natural Buttes Unit

2. NAME OF OPERATOR
Enron Oil & Gas Co.

8. FARM OR LEASE NAME

3. ADDRESS OF OPERATOR
P. O. Box 1815, Vernal, Utah 84078

9. WELL NO.
21-20B

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface

1037' FNL & 1033' FEL (NE/NE)

10. FIELD AND POOL, OR WILDCAT
NBU-Wasatch

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20, T9S, R20E

14. PERMIT NO.
43-047-30359

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
4785' KB

12. COUNTY OR PARISH
Uintah

13. STATE
Utah

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:

- TEST WATER SHUT-OFF ☐
- FRACTURE TREAT ☐
- SHOOT OR ACIDIZE ☐
- REPAIR WELL ☐
- (Other)
- PULL OR ALTER CASING ☐
- MULTIPLE COMPLETE ☐
- ABANDON* ☐
- CHANGE PLANS ☐

SUBSEQUENT REPORT OF:

- WATER SHUT-OFF ☐
- FRACTURE TREATMENT ☐
- SHOOTING OR ACIDIZING ☐
- REPAIRING WELL ☐
- ALTERING CASING ☐
- ABANDONMENT* ☐
- (Other) Cond. Tank Removal XX

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

This is to inform you that the cond. tank has been removed from this location. Attached please find a revised wellsite diagram.

OIL AND GAS

SLS

1- MICROFILM ✓

2 FILE

18. I hereby certify that the foregoing is true and correct

SIGNED *Linda L. Wall* TITLE *Sr. Admin Clerk* DATE *3-22-90*

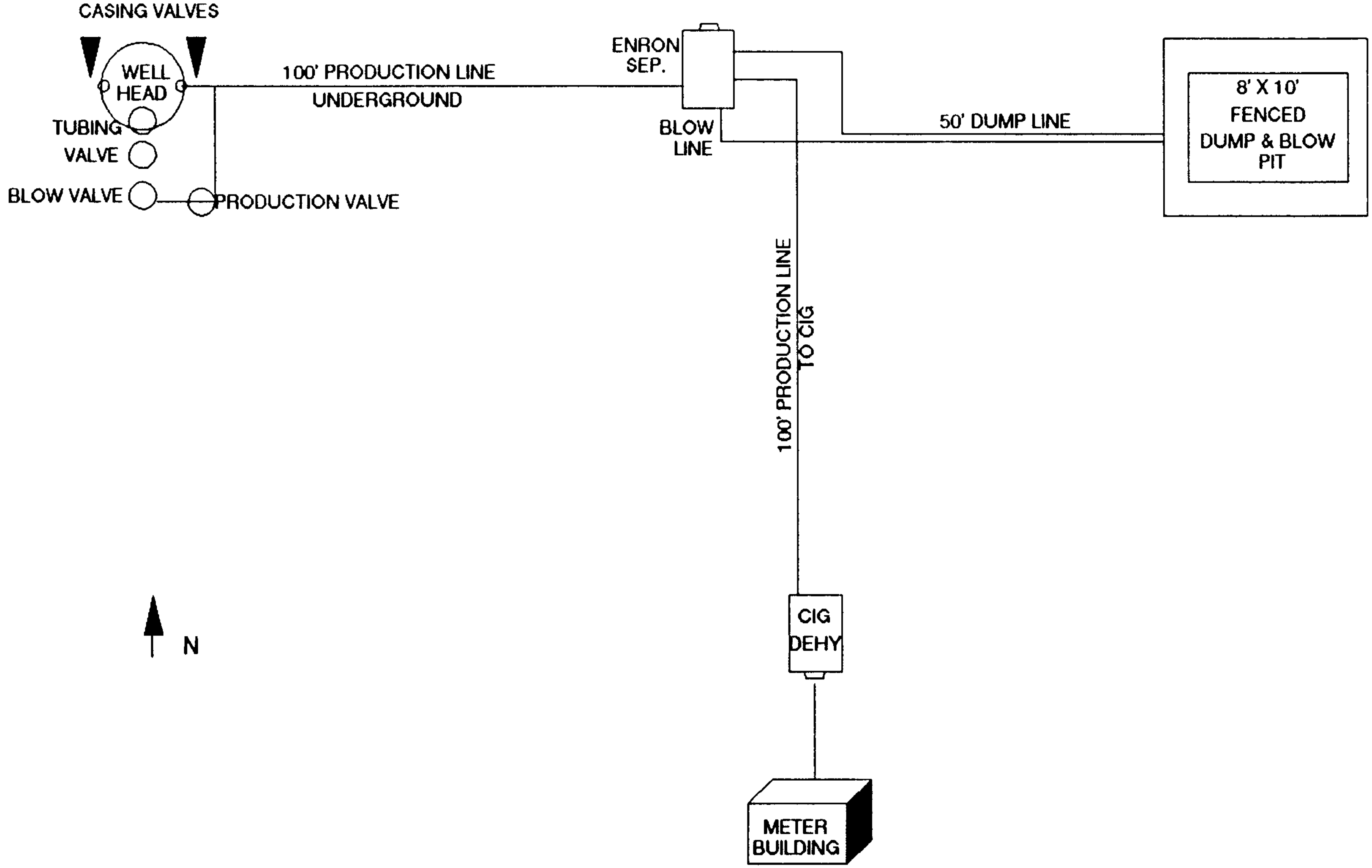
(This space for Federal or State office use)

APPROVED BY ______ TITLE ______ DATE ______

CONDITIONS OF APPROVAL, IF ANY:

*See Instructions on Reverse Side

NATURAL BUTTES 21-20
SEC. 21, T9S, R20E
UINTAH COUNTY, UTAH
LEASE NO. U-0144869



SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549

Form 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 1991

☐ TRANSITION REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number: 1-9743

ENRON OIL & GAS COMPANY

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**47-0684736** (I.R.S. Employer Identification No.)

1400 Smith Street, Houston, Texas 77002-7369
(Address of principal executive offices) (zip code)

Registrant's telephone number, including area code: 713-853-6161

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, without par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐.

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Aggregate market value of the voting stock held by non-affiliates of the registrant, based on the closing sale price in the daily composite list for transactions on the New York Stock Exchange on March 2, 1992 was $205,008,858. As of March 2, 1992, there were 75,900,000 shares of registrant's Common Stock, without par value, outstanding.

Documents incorporated by reference. Certain portions of the registrant's definitive Proxy Statement for the May 5, 1992 Annual Meeting of Stockholders ("Proxy Statement") are incorporated in Part III by reference.

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PART I

Item 1. *Business*

General

Enron Oil & Gas Company (the "Company"), a Delaware corporation, is engaged in the exploration for, and the development and production of, natural gas and crude oil primarily in major producing basins in the United States and, to a lesser extent, in Canada and selected other international areas. At December 31, 1991, the Company's estimated net proved natural gas reserves were 1,585 billion cubic feet ("Bcf") and estimated net proved crude oil, condensate and natural gas liquids reserves were 20.3 million barrels ("MMBbl"). At such date, approximately 90% of the Company's reserves (on a natural gas equivalent basis) was located in the United States and 10% in Canada. As of December 31, 1991, the Company employed approximately 630 persons.

The Company's core areas are the Big Piney area in Wyoming, the Matagorda Trend area located in federal waters offshore Texas and South Texas primarily centered in the Lobo Trend area. The Company's other domestic natural gas and crude oil producing properties are located primarily in other areas of Texas, Utah, New Mexico, Oklahoma and California. At December 31, 1991, 93% of the Company's proved domestic reserves (on a natural gas equivalent basis) was natural gas and 7% was crude oil, condensate and natural gas liquids. A substantial portion of the Company's natural gas reserves is in long-lived fields with well established production histories.

Enron Corp. currently owns approximately 84% of the outstanding common stock of the Company. (See "Relationship Between the Company and Enron Corp.").

Unless the context otherwise requires, all references herein to the Company include Enron Oil & Gas Company, its predecessors and subsidiaries, including their interests in certain partnerships. Unless the context otherwise requires, all references herein to Enron Corp. include Enron Corp., its predecessors and affiliates, other than the Company and its subsidiaries.

With respect to information on the Company's working interest in wells or acreage, "net" oil and gas wells or acreage are determined by multiplying "gross" oil and gas wells or acreage by the Company's working interest in the wells or acreage. Unless otherwise defined, all references to wells are gross.

Business Segments

The Company's operations are all natural gas and crude oil exploration and production related. Accordingly, such operations are classified as one business segment.

Exploration and Production

The Company's five principal U.S. producing areas are the Big Piney area, the Matagorda Trend area, the Lobo Trend area, the Vernal area and the Pitchfork Ranch field. These properties comprised approximately 70% of the Company's domestic reserves and 75% of the Company's maximum net gas deliverability as of December 31, 1991 and are all operated by the Company, with the exception of a portion of the Matagorda Trend area. The Company also has operations in Canada and is conducting exploration in selected other international areas.

Big Piney Area. The Company's largest reserve accumulation is located in the Big Piney area in Sublette and Lincoln counties in southwestern Wyoming. The Company is the holder of the largest productive acreage base in this area, with approximately 165,000 net acres under lease directly within field limits. A portion of the natural gas production from new wells drilled on the Company's leases in the Big Piney area can be classified as tight formation gas. (See "Other Matters – Tight Gas Sand Tax Credits (Section 29) and Severance Tax Exemption"). The Company operates approximately 400 natural gas wells with a 91% average working interest. Production net to the Company averaged

97 million cubic feet ("MMcf") per day of natural gas and 1.3 thousand barrels ("MBbl") per day of crude oil, condensate, and natural gas liquids in 1991. At December 31, 1991, maximum natural gas deliverability net to the Company was approximately 137 MMcf per day.

The current principal producing intervals are the Frontier and Mesaverde formations. The Frontier formation, which occurs at 6,500-10,000 feet, contains approximately 75% of the Company's current Big Piney reserves. The Company drilled 31 wells in the Big Piney area in 1991 and anticipates an active drilling program will continue for several years.

Matagorda Trend Area. The Company has an interest in several fields in the Matagorda Trend area, located 20 miles south of Port O'Connor, Texas in federal waters. The Company has a 33% working interest in Matagorda Block 604, which commenced production in August 1989. Additionally, the Company has a 78.4% working interest in Block 638 and a 91.9% working interest in Block 620, both of which are operated by the Company and commenced sales in November 1989. The Company also has working interests in Matagorda Blocks 555 and 556 fields. Natural gas sales from these areas net to the Company averaged 98 MMcf per day in 1991. At December 31, 1991, maximum natural gas deliverability net to the Company from these blocks was approximately 120 MMcf per day.

South Texas Area. The Company's activities in South Texas are focused in the Wilcox, Expanded Wilcox, Frio, Edwards Reef and Lobo producing horizons. The primary area of activity is in the Lobo Trend which occurs primarily in Webb and Zapata counties.

The Company operates approximately 400 wells in the South Texas area. Production is primarily from the Lobo sand of the Wilcox formation at depths ranging from 7,000 to 11,000 feet. The Company has approximately 135,000 acres under lease in this trend and a majority of the natural gas production from new wells drilled on the Company's leases in the South Texas Lobo area can be classified as tight formation gas. (See "Other Matters – Tight Gas Sand Tax Credits (Section 29) and Severance Tax Exemption"). Natural gas sales net to the Company averaged 136 MMcf per day in 1991. At December 31, 1991, maximum natural gas deliverability net to the Company was approximately 195 MMcf per day.

Vernal Area. In the Vernal area, located primarily in Uintah County, Utah, the Company operates approximately 150 producing wells and presently controls approximately 64,000 net acres. A majority of the natural gas production from new wells drilled on the Company's leases in the Vernal area can be classified as tight formation gas. (See "Other Matters – Tight Gas Sand Tax Credits (Section 29) and Severance Tax Exemption"). In 1991, natural gas sales from the Vernal area averaged 15 MMcf per day compared with approximately 17 MMcf per day maximum deliverability, both net to the Company. Production is from the Green River and Wasatch formations located at depths between 4,500-8,000 feet, and the Company has an average working interest of approximately 60%.

Pitchfork Ranch Field. The Pitchfork Ranch field located in Lea County, New Mexico, produces primarily from the Atoka and Morrow formations. In 1991, natural gas sales net to the Company averaged 17 MMcf per day. At December 31, 1991, maximum natural gas deliverability net to the Company was approximately 35 MMcf per day. During 1991, the Company significantly increased reserves and deliverability through drilling and workovers, a portion of which can be classified as tight formation gas.

Canada. The Company is engaged in the exploration for and the development and production of natural gas and crude oil and the operation of natural gas processing plants in western Canada, principally in the provinces of Alberta, Saskatchewan, and Manitoba. The Company has been active in western Canada since 1968 and conducts operations from offices in Calgary. As of December 31, 1991, the Company held approximately 213,000 net undeveloped acres in Canada.

Other International. The Company continues to pursue selected opportunities outside North America with activities at year end in Egypt, Indonesia, the United Kingdom North Sea, Syria, and offshore Malaysia. In 1991 and 1992, three unsuccessful wells were drilled in Syria, and efforts under that agreement are being terminated. The Company has not budgeted significant capital and exploration expense expenditures in these areas for 1992.

Marketing

Wellhead Marketing. The Company's wellhead natural gas production is currently being sold on the spot market and under long-term natural gas contracts at market responsive prices. In many instances, the long-term contract prices closely approximate the prices received for natural gas being sold on the spot market. Approximately one-half of the Company's wellhead natural gas production is currently being sold to pipeline and marketing subsidiaries of Enron Corp.

Substantially all of the Company's wellhead crude oil and condensate is sold under short-term contracts at posted prices.

Other Marketing. Enron Oil & Gas Marketing, Inc. ("EOGM"), a wholly-owned subsidiary of the Company, is a natural gas and crude oil marketing company engaging in various marketing activities. These include contracting to provide, under long-term agreements, natural gas to various purchasers and then aggregating the necessary supplies for the sales with purchases from various sources including third-party producers, marketing companies, pipelines or from the Company's own production. EOGM also utilizes shorter term hedging mechanisms including sales and purchases in the futures market as well as other longer term arrangements such as price swap agreements. EOGM's portfolio of marketing activities has provided an effective balance in managing the Company's exposure to price risks in the energy market.

The Company has four long-term natural gas sales contracts, some for as long as 10 years with an Enron Corp. subsidiary. It expects to sell up to 125 MMcf of natural gas per day in 1992 under the four agreements. Actual physicial volumes to supply these commitments may be secured from various sources such as third-party producers, marketing companies, and pipelines or from the Company's own production.

Over the life of two of the contracts, which became effective November 1, 1989, the Company will sell up to 219 Bcf of natural gas. Under a third contract, which became effective November 1, 1990, it will sell up to 54 Bcf of natural gas. Approximately 90 MMcf of natural gas per day are currently being sold under the three contracts. Under two of the contracts, all the natural gas is sold under fixed schedules of prices for the entire terms of the contracts. Under the other contract which became effective November 1, 1989, all of the natural gas is sold under a fixed schedule of prices through October 31, 1994. Beginning November 1, 1994 through the remaining term of the contract, a portion of the natural gas will be sold at market responsive prices. Under a fourth long-term contract, which became effective January 1, 1991, the Company will sell approximately 40 MMcf of natural gas per day over a ten-year period or up to 146 Bcf. The contract provides for an indexed pricing mechanism based upon spot market prices. The Company simultaneously entered into a ten-year price swap agreement with another Enron Corp. subsidiary that has the effect of fixing the price for an equivalent volume of gas at a level substantially above current spot market prices through the year 2000. Subsequently, the Company entered into another price swap agreement that has the effect of converting the price to the equivalent of a market responsive index plus a small fixed premium for the years 1996 through 1999. The Company currently anticipates that it will supply a major part of the natural gas for these sales through purchases at market responsive prices.

The Company also has contracted to supply natural gas to a cogeneration facility 50% owned by Enron Corp. The primary contract provides for the sale of natural gas under a fixed schedule of prices substantially above current spot market prices. Current deliveries of approximately 45 MMcf of natural gas per day are being supplied primarily by purchases from an Enron Corp. subsidiary under a long-term agreement with a majority of the purchases at market responsive prices and a small portion under a fixed schedule of prices. The Company has entered into a price swap agreement with a third party that has the effect of fixing the price for a volume of natural gas essentially equivalent to the volume of natural gas being purchased at market responsive prices to a fixed schedule of prices. The resulting fixed schedule of prices under this combination of purchase and price swap agreements are substantially below the fixed schedule of prices in the sales contract. The arrangements are designed, as to the volumes involved, to provide the Company a margin of profit under its agreement with Cogenron Inc.

The Company's commitments to deliver substantial volumes of natural gas under certain of the contracts containing schedules of predetermined prices discussed above would be disadvantageous to the Company during any time spot market prices exceed the applicable contract prices for natural gas. The Company may enter into similar arrangements in the future.

Wellhead Volumes and Prices, and Lease and Well Expenses

The following table sets forth certain information regarding the Company's wellhead volumes of and average wellhead sales prices received for natural gas per thousand cubic feet ("Mcf"), crude oil and condensate, and natural gas liquids per barrel ("Bbl"), and average lease and well expenses per thousand cubic feet equivalent ("Mcfe" – natural gas equivalents are determined using the ratio of 6.0 Mcf of natural gas to 1.0 barrel of crude oil, condensate or natural gas liquids) sold during each of the three years in the period ended December 31, 1991:

	Year Ended December 31,		
	1991	1990	1989
Sales Volumes (per day)			
Natural Gas (MMcf)			
United States	465.8	437.5	328.0
Canada	24.8	17.6	16.4
Total	490.6	455.1	344.4
Crude Oil and Condensate (MBbl)			
United States	5.9	5.8	5.7
Canada	2.3	2.4	2.6
Total	8.2	8.2	8.3
Natural Gas Liquids (MBbl)			
United States	0.3	0.4	0.5
Canada	0.3	–	–
Total	0.6	0.4	0.5
Average Prices			
Natural Gas ($/Mcf)			
United States	$ 1.38	$ 1.51	$ 1.61
Canada	1.32	1.47	1.61
Composite	1.37	1.51	1.61
Crude Oil and Condensate ($/Bbl)			
United States	$19.24	$21.95	$17.82
Canada	17.58	21.01	15.32
Composite	18.78	21.67	17.04
Natural Gas Liquids ($/Bbl)			
United States	$10.79	$10.59	$ 9.87
Canada	12.48	–	–
Composite	11.64	10.59	9.87
Lease and Well Expenses ($/Mcfe)			
United States	$ .23	$ .21	$ .25
Canada	.57	.57	.58
Composite	.25	.24	.28

Other Natural Gas Marketing Volumes and Prices

The following table sets forth certain information regarding the Company's volumes of other natural gas sales and purchases, and resulting average sales prices and purchase costs during each of the three years in the period ended December 31, 1991. (See "Marketing" for a discussion of other natural gas marketing arrangements and agreements).

	Year Ended December 31,		
	1991	1990	1989
Volumes (MMcf per day)	237.2	153.9	67.1
Average Sales Prices ($/Mcf)	$ 2.63	$ 2.90	$ 3.30
Average Purchase Costs ($/Mcf)(1)	1.75	1.99	2.07
Margin ($/Mcf)	$ .88	$ .91	$ 1.23

(1) Including transportation.

Competition

The Company actively competes for reserve acquisitions and exploration leases, licenses and concessions, frequently against companies with substantially larger financial and other resources. To the extent the Company's exploration budget is lower than that of certain of its competitors, the Company may be disadvantaged in effectively competing for certain reserves, leases, licenses and concessions. Competitive factors include price, contract terms, and quality of service, including pipeline connection times and distribution efficiencies. In addition, the Company faces competition from other producers and suppliers, including increased competition from Canadian natural gas.

Regulation

Domestic Regulation of Natural Gas and Crude Oil Production. Natural gas and crude oil production operations are subject to various types of regulation, including regulation in the United States by state and federal agencies.

Domestic legislation affecting the oil and gas industry is under constant review for amendment or expansion. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue and have issued rules and regulations which, among other things, require permits for the drilling of wells, regulate the spacing of wells, prevent the waste of natural gas and crude oil resources through proration, require drilling bonds and regulate environmental and safety matters. The regulatory burden on the oil and gas industry increases its cost of doing business and, consequently, affects its profitability.

A substantial portion of the Company's oil and gas leases in the Big Piney area and in the Gulf of Mexico, as well as some in other areas, are granted by the federal government and administered by the Bureau of Land Management (the "BLM") and the Minerals Management Service (the "MMS") federal agencies. Operations conducted by the Company on federal oil and gas leases must comply with numerous statutory and regulatory restrictions. Certain operations must be conducted pursuant to appropriate permits issued by the BLM and the MMS.

Sales of crude oil, condensate and natural gas liquids by the Company can be made at uncontrolled market prices.

The transportation and sale for resale of natural gas in interstate commerce are regulated pursuant to the Natural Gas Act of 1938 (the "NGA") and the Natural Gas Policy Act of 1978 (the "NGPA"). These statutes are administered by the Federal Energy Regulatory Commission (the "FERC"). The NGPA established various categories of natural gas and provides for graduated deregulation of price controls of several categories of natural gas and the deregulation of sales of certain categories of natural gas. Under the Natural Gas Wellhead Decontrol Act of 1989 (the

"Decontrol Act"), certain natural gas previously subject to NGPA and NGA price and non-price controls became decontrolled. Pursuant to the Decontrol Act, all NGPA and NGA price and non-price controls affecting wellhead sales of natural gas will be removed by January 1, 1993. The Company is unable to predict the consequences of the Decontrol Act on its operations.

Regulation of natural gas importation is administered primarily by the Department of Energy's Economic Regulatory Administration (the "ERA"), pursuant to the NGA. The NGA provides that any party seeking to import natural gas must first seek ERA authorization, which authorization may be granted, modified or denied in accordance with the public interest.

Commencing in late 1985 and early 1986, the FERC issued a series of orders (Order No. 436, Order No. 500, Order No. 528 and related orders), which significantly altered the marketing and pricing of natural gas. The general applicability of several of these orders has been contested in the Federal courts. Among other things, the new regulations (i) require interstate pipelines that elect to transport gas for others under self-implementing authority to provide transportation services to all shippers on a non-discriminatory basis; (ii) permit each existing firm sales customer of such pipelines to modify over at least a five-year period its existing purchase obligations; (iii) establish guidelines that permit pipelines to recover from customers a portion of payments made to producers in settlement of take-or-pay contract disputes.

Most of the major interstate pipelines have accepted authorizations from the FERC to perform non-discriminatory transportation under these rules, while others have settlement proceedings pending before the FERC to permit them to operate under the new regulations. The "spot" market for natural gas has been greatly enlarged by, among other things, the availability of transportation services under Order No. 436 and related orders. Additionally, the National Energy Board of Canada has dramatically revised its gas export policies to permit large volumes of Canadian gas to compete with gas produced in the U.S. for the U.S. spot market. Additional natural gas pipeline capacity from Canada to the U.S. has been built and other such construction proposals are pending approval. Certain policies of the Department of Energy encourage importation of such Canadian gas. Canadian gas competes directly with gas produced from the Company's Big Piney area for customers located in the Pacific Northwest region of the United States.

The effect of Order No. 500 and Order No. 528 is to suggest several permissible alternative proposals for passthrough of take-or-pay costs, including allocation and direct billing based on current firm customers' contract rights, allocation and direct billing based on current throughput volumes or collection through a surcharge applied to actual volumes sold and transported. Some pipelines have passthrough agreements with their customers that are unaffected by court decisions and Order No. 528. Those pipelines that do not will be forced to apply to collect past take-or-pay costs from current and future sales and transportation customers in accordance with Order No. 528. Pipelines required to make refunds or unable to make such collection may be able to invoke "FERC out" type clauses in producer natural gas contracts and settlements. The most likely effect upon the Company, if any, would be an increase in the take-or-pay surcharge components of the transportation tariffs pursuant to which it and all other shippers similarly situated have natural gas transported. Management does not believe that any such increase in transportation rates would have a material adverse effect on the financial condition or results of operations of the Company.

In July 1991 the FERC issued a proposed rule that, if promulgated, would significantly restructure the gas pipeline industry by requiring gas pipelines to "unbundle" or segregate the sales, transportation, and other components of their existing city-gate sales service. The purpose of the proposed rule is to further enhance competition in the gas industry. The proposed rule would not directly regulate the Company's activities, but may have an indirect effect because of its broad scope. Since the FERC's final rule has not yet been issued, the precise form of the rule is not known at this time. While the Company cannot predict the effects of the rule, if issued, the Company believes it may create initial confusion and uncertainty, and may cause pipelines to seek to renegotiate or

terminate certain of their existing purchase contracts, but ultimately may enhance the Company's ability to market and transport its gas production.

In February 1988, the FERC approved new abandonment rules (Order No. 490) for expired, cancelled, or modified contracts. The abandonment authorization required to effectuate the Company's release from Big Piney long-term natural gas purchase contracts with Northwest Pipeline Corporation was obtained pursuant to Order No. 490. Appeals of Order No. 490 and related orders are currently pending. The Company cannot predict the outcome of these proceedings, but Supreme Court precedent sustaining portions of another generic abandonment order arguably applies as well to Order No. 490 and therefore may strengthen its chances of being sustained on appeal. In the event Order No. 490 is vacated, the Company would be required to use or obtain, if possible, other abandonment authority to implement this settlement. The Company believes that such authorities either exist or could be obtained.

In December, 1991, the FERC extended for another year its Order No. 497 regulations, which establish standards of conduct, record keeping and reporting requirements and other measures to govern relationships between interstate pipelines and their marketing affiliates. These regulations are subject to pending appeals. The regulations under the Order do not directly regulate the Company's activities, although a substantial portion of the Company's natural gas production is sold to or transported by interstate pipeline affiliates which are subject to the order. The Company's activities may therefore be indirectly affected by these regulations.

The Company cannot predict the effect that any of the aforementioned orders or the challenges to such orders will ultimately have on the Company's operations. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC and the courts. These include several energy bills and executive branch initiatives that seek to decrease reliance by the United States on foreign crude oil and propose, among other things, to streamline or eliminate the certification process for certain types of natural gas pipelines. The Company cannot predict when or whether any such proposals or proceedings may become effective.

Environmental Regulation. Various federal, state and local laws and regulations covering the discharge of materials into the environment, or otherwise relating to the protection of the environment, may affect the Company's operations and costs as a result of their effect on natural gas and crude oil exploration, development and production operations. It is not anticipated that the Company will be required in the near future to expend amounts that are material in relation to its total capital and exploration expense expenditure program by reason of environmental laws and regulations, but inasmuch as such laws and regulations are frequently changed, the Company is unable to predict the ultimate cost of compliance.

The Company has been named as a potentially responsible party in certain Comprehensive Environmental Response Compensation and Liability Act proceedings. However, management does not believe that any potential assessments resulting from such proceedings will individually or in the aggregate have a materially adverse effect on the financial condition or results of operations of the Company.

Canadian Regulation. In Canada, the petroleum industry operates under Federal, provincial and municipal legislation and regulations governing land tenure, royalties, production rates, pricing, environmental protection, exports and other matters. The price of natural gas and crude oil in Canada has been deregulated and is now determined by market conditions and negotiations between buyers and sellers.

Various matters relating to the transportation and export of natural gas continue to be subject to regulation by both provincial and Federal agencies; however, the Canada U.S. Free Trade Agreement has reduced the risk of altering cross-border commercial transactions.

Canadian governmental regulations may have a material effect on the economic parameters for engaging in oil and gas activities in Canada and may have a material effect on the advisability of investments in Canadian oil and gas drilling activities. The Company is monitoring political, regulatory and economic developments in Canada.

Relationship Between The Company And Enron Corp.

Ownership of Common Stock. Enron Corp. owns approximately 84% of the Company's outstanding shares and, through its ability to elect all directors of the Company, has the ability to control all matters relating to the management of the Company, including any determination with respect to acquisition or disposition of Company assets, future issuance of common stock or other securities of the Company and any dividends payable on the common stock. Enron Corp. also has the ability to control the Company's exploration, development, capital, operating and acquisition expenditure plans. If Enron Corp. should sell a substantial amount of the common stock of the Company that it owns, this action could adversely affect the prevailing market price for the common stock and could impair the Company's ability to raise capital through the sale of its equity securities. The Company has granted certain registration rights to Enron Corp. with respect to the common stock owned by Enron Corp. (See "Contractual Arrangements" below). There is no agreement between Enron Corp. and any other party, including the Company, that would prevent Enron Corp. from acquiring additional shares of common stock.

Contractual Arrangements. The Company has entered into a Services Agreement (the "Services Agreement") with Enron Corp. effective January 1, 1989 pursuant to which Enron Corp. provides various services, such as maintenance of certain employee benefit plans, provision of telecommunications and computer systems, lease of office space and the provision of certain purchasing and operating services and certain other corporate staff and support services. Such services historically have been supplied to the Company by Enron Corp., and the Services Agreement provides for the further delivery of such services substantially identical in nature and quality to those services previously provided. The Company has agreed to a fixed rate for the rental of office space and to reimburse Enron Corp. for all other direct costs incurred in rendering services to the Company under the contract and to pay Enron Corp. for allocated indirect costs incurred in rendering such services up to an annual maximum of $8 million, such cap to be increased for inflation and certain changes in the Company's allocation bases with the increase limited to a maximum of 10% per year. The Services Agreement is for an initial term of five years and shall continue thereafter until terminated by either party upon written notice to the other party.

The Company is included in the consolidated federal income tax return filed by Enron Corp. as the common parent for itself and its subsidiaries and affiliated companies, excluding any foreign subsidiaries. Consistent therewith and pursuant to the Tax Allocation Agreement (the "Tax Agreement") entered into by Enron Corp., the Company and the Company's subsidiaries, either Enron Corp. will pay to the Company and each subsidiary an amount equal to the tax benefit realized in the Enron Corp. consolidated federal income tax return resulting from the utilization of the Company's or the subsidiary's net operating losses and tax credits, or the Company and each subsidiary will pay to Enron Corp. an amount equal to the federal income tax computed on its separate taxable income less any net operating losses or tax credits generated by the Company or the subsidiary which are utilized in the Enron Corp. consolidated return. The Company and each subsidiary will pay such amount even if the consolidated federal income tax return to which such payment relates does not set forth a consolidated tax liability. Enron Corp. will pay the Company and each subsidiary for their net operating losses and tax credits utilized in the Enron Corp. consolidated return, provided that a tax benefit was realized except as discussed in the following paragraph, even if such credits could not have been used by the Company or the subsidiary on a separately filed tax return.

In 1991, the Company and Enron Corp. modified the Tax Agreement to provide that, through 1992, the Company will realize the benefit of certain tight gas sand tax credits available to the Company on a stand alone basis. The Company has also entered into an agreement with Enron Corp. providing for the Company to be paid for all realizable benefits associated with tight gas sand tax credits concurrent with tax reporting and settlement for the periods in which they are generated.

The Tax Agreement applies to the Company and each of its subsidiaries for all years in which the Company or any of its subsidiaries are or were included in the Enron Corp. consolidated return.

To the extent a state or other taxing jurisdiction requires or permits a consolidated, combined, or unitary tax return to be filed and such return includes the Company or any of its subsidiaries, the principles expressed with respect to consolidated federal income tax allocation shall apply.

Pursuant to the terms of a Stock Restriction and Registration Agreement with Enron Corp., the Company has agreed that upon the request of Enron Corp. (or certain assignees), the Company will register under the Securities Act of 1933 and applicable state securities laws the sale of the common stock owned by Enron Corp. which Enron Corp. has requested to be registered. The Company's obligation is subject to certain limitations relating to a minimum amount of common stock required for registration, the timing of registration and other similar matters. The Company is obligated to pay all expenses incidental to such registration, excluding underwriters' discounts and commissions and certain legal fees and expenses.

Conflicts of Interest. The nature of the respective businesses of the Company and Enron Corp. and its affiliates is such as to potentially give rise to conflicts of interest between the two companies. Conflicts could arise, for example, with respect to transactions involving purchases, sales and transportation of natural gas and other business dealings between the Company and Enron Corp. and its affiliates, potential acquisitions of businesses or oil and gas properties, the issuance of additional shares of voting securities, the election of directors or the payment of dividends by the Company.

Enron Corp. has advised the Company that it does not currently intend to engage in the exploration for natural gas and crude oil except through its ownership of common stock of the Company. However, circumstances may arise that would cause Enron Corp. to engage in the exploration for natural gas and crude oil in competition with the Company. For example, opportunities might arise which would require financial resources greater than those available to the Company or which are located in areas or countries in which the Company does not intend to operate. Also, Enron Corp. might acquire a competing oil and gas business as part of a larger acquisition. In addition, as part of Enron Corp.'s strategy of securing supplies of natural gas, Enron Corp. may from time to time acquire producing properties, and thereafter engage in production and development activities with respect to such properties. Such acquisition, production and development activities may directly or indirectly compete with the Company's business. Thus, although Enron Corp. has indicated no current intention to do so, there can be no assurances that it will not engage in the natural gas and crude oil exploration and production business in competition with the Company.

The Company and Enron Corp. and its affiliates have in the past entered into significant intercompany transactions and agreements incident to their respective businesses, and the Company and Enron Corp. and its affiliates may be expected to enter into material transactions and agreements from time to time in the future. Such transactions and agreements have related to, among other things, the purchase and sale of natural gas, the financing of exploration and development efforts by the Company, and the provision of certain corporate services. (See "Marketing" and the Consolidated Financial Statements and notes thereto). The Company intends that the terms of any future transactions and agreements between the Company and Enron Corp. and its affiliates will be at least as favorable to the Company as could be obtained from third parties.

Other Matters

Energy Prices. Since the Company is primarily a natural gas company, it is more significantly impacted by changes in natural gas prices than in the prices for crude oil, condensate and natural gas liquids. During recent periods, natural gas has been priced significantly below parity with crude oil, condensate and natural gas liquids based on the energy equivalency of, and differences in transportation and processing costs associated with, the respective products. This imbalance in parity is impacted by, among other things, a supply of domestic natural gas volumes in excess of demand requirements. The Company is unable to predict when this supply imbalance may resolve due to the significant impacts of factors such as general economic conditions, weather and other international energy supplies over which the Company has no control.

Crude oil, condensate and natural gas liquids prices fluctuated dramatically during the early part of 1991 as a result of the war in the Persian Gulf area and the events leading up to the conflict. Due to the many uncertainties associated with the Middle East situation and availabilities of other world wide crude oil, condensate and natural gas liquids supplies, the Company is unable to predict what changes may occur in these product prices in the future.

Tight Gas Sand Tax Credits (Section 29) and Severance Tax Exemption. Federal tax law provides a tax credit for production of certain fuels produced from nonconventional sources (including natural gas produced from tight formations), subject to a number of limitations. Fuels qualifying for the credit must be produced from a well drilled or a facility placed-in-service before January 1, 1993, and sold before January 1, 2003.

The credit, which is currently approximately $.52 per MMBtu of natural gas, is computed by reference to the price of crude oil, and is phased out as the price of crude oil exceeds $23.50 in 1980 dollars (adjusted for inflation) with complete phaseout if such price exceeds $29.50 in 1980 dollars (similarly adjusted). Under this formula, the commencement of phaseout would be triggered if the average price for crude oil rose above approximately $40 per barrel in current dollars. Significant benefits from the tax credit are accruing to the Company since a portion (and in some cases a substantial portion) of the Company's natural gas production from new wells drilled on the Company's leases in several of the Company's significant producing areas qualify for this tax credit. Depending on the availability of the credit, the Company may make adjustments to its capital and exploration expense expenditures to focus drilling efforts on properties the production from which qualifies for the credit.

Certain natural gas production from wells spudded or completed between May 24, 1989 and September 1, 1996 in tight formations in Texas may qualify for a ten year exemption, ending August 31, 2001, from Texas severance taxes, subject to certain limitations.

Other. All of the Company's oil and gas activities are subject to the risks normally incidental to the exploration for, and development and production of, crude oil and natural gas, including blowouts, cratering and fires, each of which could result in damage to life and property. Offshore operations are subject to usual marine perils, including hurricanes and other adverse weather conditions, and governmental regulations as well as interruption or termination by governmental authorities based on environmental and other considerations. In accordance with customary industry practices, insurance is maintained by the Company against some, but not all, of the risks. Losses and liabilities arising from such events could reduce revenues and increase costs to the Company to the extent not covered by insurance.

The Company's overseas operations, which are not currently material, are subject to certain risks, including expropriation of assets, risks of increases in taxes and government royalties, renegotiation of contracts with foreign governments, political instability, payment delays, limits on allowable levels of production and current exchange and repatriation losses, as well as changes in laws and policies governing operations of overseas-based companies generally.

Current Executive Officers of the Registrant

The current executive officers of the Company and their names and ages are as follows:

Name	Age	Position
Forrest E. Hoglund	58	Chairman of the Board, President and Chief Executive Officer; Director
Lewis P. Chandler, Jr.	51	Senior Vice President-Law
Howard Karren	61	President, Enron Exploration Company
Mark G. Papa	45	Senior Vice President-Operations
George E. Uthlaut	58	Senior Vice President-Operations
Walter C. Wilson	49	Senior Vice President and Chief Financial Officer
Ben B. Boyd	50	Vice President and Controller
J. Chris Bryan	44	Vice President-Administration & Human Resources
Ralph C. Lamb, Jr.	60	Vice President-Exploration
Dennis M. Ulak	37	Vice President and General Counsel

Forrest E. Hoglund joined the Company as Chairman of the Board, Chief Executive Officer and Director in September 1987. Since May 1990 he has also served as President of the Company. Mr. Hoglund was a director of USX Corporation from February 1986 until September 1987. He joined Texas Oil & Gas Corp. ("TXO") in 1977 as president, was named Chief Operating Officer in 1979, Chief Executive Officer in 1982, and served TXO in those capacities until September 1987. Mr. Hoglund is also a director of Texas Commerce Bancshares, Inc.

Lewis P. Chandler, Jr. has been Senior Vice President-Law since March 1992. Mr. Chandler joined the Company in December 1973 and has since served in a number of positions in the Company's legal department. He was appointed Vice President and General Counsel for BelNorth Petroleum Corp. in June 1983 and was named Vice President and General Counsel for the Company in January 1987. In May 1991, he was named Senior Vice President and General Counsel for the Company.

Howard Karren has been President of Enron Exploration Company, a subsidiary of the Company, since December 1986. Mr. Karren joined HNG Exploration Company as President in January 1985 and has since been responsible for the Company's international exploration and production activities. Prior to joining the Company, Mr. Karren was President of Natomas Petroleum International, Inc.

Mark G. Papa has been Senior Vice President-Operations since May 1986. Mr. Papa joined the Company in 1981 as Division Production Coordinator and served as Senior Vice President-Drilling and Production, BelNorth Petroleum Corporation from May 1984 until assuming his current position.

George E. Uthlaut has been Senior Vice President-Operations of the Company since November 1987. Mr. Uthlaut was previously employed by Exxon Corporation (and affiliates) for 29 years in a number of managerial and technical positions. His last position was Headquarters Operations Manager, Production Department, Exxon Company, USA.

Walter C. Wilson has been Senior Vice President and Chief Financial Officer since May 1991. Mr. Wilson joined the Company in November 1987 as Vice President and Controller and was named Senior Vice President-Finance in October 1988. Prior to joining the Company Mr. Wilson held financial management positions with Exxon Company, USA for 16 years and The Superior Oil Company for 4 years.

Ben B. Boyd has been Vice President and Controller since March 1991. Mr. Boyd joined the Company in March 1989 as Director of Accounting and was named Controller in May 1990. Prior to joining the Company, Mr. Boyd held financial management positions with DeNovo Oil & Gas, Inc., Scurlock Oil Company and Coopers & Lybrand.

J. Chris Bryan has been Vice President-Administration & Human Resources since May 1986. From December 1984 to March 1986 Mr. Bryan served as Vice President-Human Resources of Houston Natural Gas Corporation. Prior to joining Houston Natural Gas Corporation, Mr. Bryan held management positions in Human Resources with Natomas North America, Inc. and Diamond Shamrock.

Ralph C. Lamb, Jr. has been Vice President-Exploration since joining the Company in March 1988. Prior to that time, Mr. Lamb was employed for over 25 years with Chevron Corp. in various technical and managerial positions. After leaving Chevron Corp., Mr. Lamb held management positions with Ratliff Exploration Company and TXO for four years.

Dennis M. Ulak has been Vice President and General Counsel since March 1992. Mr. Ulak joined the Company in March 1987 as Senior Counsel and was named Assistant General Counsel in August 1990. Prior to joining the Company, Mr. Ulak held various legal positions with Enron Corp. and Northern Natural Gas Company.

Item 2. *Properties*

Oil and Gas Exploration and Production Properties and Reserves

Reserve Information. For estimates of the Company's net proved and proved developed reserves of natural gas and liquids, including crude oil, condensate and natural gas liquids, see "Supplemental Information to Consolidated Financial Statements."

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the control of the producer. The reserve data set forth in Supplemental Information to Consolidated Financial Statements represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of natural gas and liquids, including crude oil, condensate and natural gas liquids, that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the amount and quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers normally vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities ultimately recovered. The meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they were based.

In general, the volume of production from oil and gas properties owned by the Company declines as reserves are depleted. Except to the extent the Company acquires additional properties containing proved reserves or conducts successful exploration and development activities, or both, the proved reserves of the Company will decline as reserves are produced. Volumes generated from future activities of the Company are therefore highly dependent upon the level of success in acquiring or finding additional reserves and the costs incurred in doing so.

The Company's estimates of reserves filed with other federal agencies agree with the information set forth in Supplemental Information to Consolidated Financial Statements.

Acreage. The following table summarizes the Company's developed and undeveloped acreage at December 31, 1991. Excluded is acreage in which the Company's interest is limited to owned royalty, overriding royalty and other similar interests.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
United States						
Texas	409,973	246,863	146,034	124,236	556,007	371,099
Federal Offshore	214,481	86,155	231,615	198,502	446,096	284,657
Wyoming	148,238	103,183	172,209	118,678	320,447	221,861
New Mexico	112,115	46,304	65,933	43,647	178,048	89,951
Utah	75,212	51,226	55,467	23,313	130,679	74,539
Oklahoma	116,193	58,957	27,732	18,826	143,925	77,783
California	16,389	14,162	22,127	19,594	38,516	33,756
Colorado	29,034	3,519	84,804	34,951	113,838	38,470
Kansas	4,545	3,955	11,720	10,269	16,265	14,224
Nevada	-	-	41,153	8,631	41,153	8,631
Montana	122,534	1,169	24,971	6,319	147,505	7,488
Arkansas	6,342	-	2,824	-	9,166	-
Louisiana	2,209	987	5,206	1,180	7,415	2,167
North Dakota	3,015	1,186	3,277	2,694	6,292	3,880
Other	1,761	406	2,240	1,294	4,001	1,700
Total U.S.	1,262,041	618,072	897,312	612,134	2,159,353	1,230,206
Canada						
Alberta	381,884	173,174	262,471	132,360	644,355	305,534
Saskatchewan	7,672	7,672	65,164	62,724	72,836	70,396
Manitoba	12,785	8,469	17,678	17,531	30,463	26,000
British Columbia	656	164	-	-	656	164
Total Canada	402,997	189,479	345,313	212,615	748,310	402,094
Other International						
Malaysia	-	-	2,283,204	970,362	2,283,204	970,362
Egypt	-	-	1,284,920	642,460	1,284,920	642,460
Syria	-	-	624,300	374,580	624,300	374,580
Indonesia	-	-	527,213	206,613	527,213	206,613
United Kingdom	-	-	199,855	49,964	199,855	49,964
Total Other International	-	-	4,919,492	2,243,979	4,919,492	2,243,979
Total	1,665,038	807,551	6,162,117	3,068,728	7,827,155	3,876,279

Producing Well Summary. The following table reflects the Company's ownership in gas wells in 324 fields and oil wells in 119 fields located in Texas, offshore Texas and Louisiana in the Gulf of Mexico, Oklahoma, New Mexico, Utah, Wyoming and various other states and Canada at December 31, 1991. Gross oil and gas wells include 111 with multiple completions.

	Productive Wells	
	Gross	Net
Gas	2,542	1,462
Oil	1,209	589
Total	3,751	2,051

Drilling and Acquisition Activities. During the years ended December 31, 1991, 1990 and 1989 the Company spent approximately $254.8, $300.3 and $230.0 million, respectively, for exploratory and development drilling and acquisition of leases and producing properties. The Company drilled, participated in the drilling of or acquired wells as set out in the table below for the periods indicated:

	Year Ended December 31,					
	1991		1990		1989	
	Gross	Net	Gross	Net	Gross	Net
Development Wells Completed						
Domestic						
Gas	193	165.25	124	93.79	109	86.43
Oil	6	3.89	19	8.86	9	4.76
Dry	29	21.43	23	18.45	14	10.21
Total	228	190.57	166	121.10	132	101.40
International						
Gas	8	5.33	18	11.73	16	7.31
Oil	9	8.50	29	27.15	19	14.36
Dry	4	2.86	6	4.71	3	1.11
Total	21	16.69	53	43.59	38	22.78
Total Development	249	207.26	219	164.69	170	124.18
Exploratory Wells Completed						
Domestic						
Gas	14	10.54	12	6.98	8	5.24
Oil	1	1.00	2	1.40	1	0.35
Dry	13	10.38	22	17.20	14	10.42
Total	28	21.92	36	25.58	23	16.01
International						
Gas	3	1.83	13	6.70	17	10.58
Oil	1	.39	6	5.50	3	1.65
Dry	9	5.48	8	5.70	23	14.94
Total	13	7.70	27	17.90	43	27.17
Total Exploratory	41	29.62	63	43.48	66	43.18
Total	290	236.88	282	208.17	236	167.36
Wells in Progress at end of period	32	21.60	26	15.04	43	25.73
Total	322	258.48	308	223.21	279	193.09
Wells Acquired						
Gas	100	70.10*	262	182.68*	78	15.54*
Oil	5	4.10*	–	–	–	–
Total	105	74.20	262	182.68	78	15.54

* Includes the acquisition of additional interests in wells in which the Company previously held an interest.

All of the Company's drilling activities are conducted on a contract basis with independent drilling contractors. The Company owns no drilling equipment.

Item 3. *Legal Proceedings*

The Company and its subsidiaries and related companies are named defendants in numerous lawsuits and named parties in numerous governmental proceedings arising in the ordinary course of business. While the outcome of lawsuits or other proceedings against the Company cannot be

predicted with certainty, management and counsel do not expect these matters to have a material adverse effect on the financial condition or results of operations of the Company. Two lawsuits currently pending in South Texas question the manner in which the Company calculates royalty payments under oil and gas leases requiring payment of royalty based upon the market value of natural gas at the well. Plaintiffs in these lawsuits have asserted that market value at the well should be based upon prices received by affiliates of the Company who purchase the natural gas from the Company and resell it to non-affiliated third parties. The Company takes the position that market value at the well should be determined based upon the prevailing price being paid for comparable sales of natural gas in the field where the natural gas is produced. If the courts were to finally determine that market value at the well should be based upon the price received by an affiliate when such natural gas is resold to a non-affiliated third party, less a deduction for transportation, the Company might be required to change its method of calculating royalty payments in those instances where the Company's natural gas is sold to an affiliate. While the Company cannot predict the outcome of this litigation or its subsequent application, it does not believe the courts will require the Company to make royalty payments on a value in excess of current market value at the well. Therefore, management does not believe the outcome of these cases will materially affect the Company.

Item 4. *Submission of Matters to a Vote of Security Holders*

There were no matters submitted to a vote of security holders during the fourth quarter of 1991.

PART II

Item 5. ***Market for the Registrant's Common Equity and Related Stockholder Matters***

The following table sets forth, for the periods indicated, the high and low sale prices per share for the common stock, as reported on the New York Stock Exchange Composite Tape, and the amount of cash dividends paid per share.

	Price Range		Cash
	High	Low	Dividends
1989			
Fourth Quarter (beginning October 4, 1989)	$25.25	$19.00	-
1990			
First Quarter	25.00	20.63	$ .05
Second Quarter	24.75	20.75	.05
Third Quarter	30.13	22.00	.05
Fourth Quarter	28.38	19.88	.05
1991			
First Quarter	22.25	16.25	.05
Second Quarter	21.50	18.00	.05
Third Quarter	24.63	17.63	.05
Fourth Quarter	25.13	19.25	.05

As of March 9, 1992, there were approximately 3,500 holders of the Company's common stock.

Since the Company's initial public offering of its common stock in October 1989, the Company has paid quarterly dividends of $0.05 per share beginning with an initial dividend paid in January 1990 with respect to the fourth quarter of 1989. The Company currently intends to continue to pay quarterly cash dividends on its outstanding shares of common stock. However, the determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other things, the Company's financial condition, funds from operations, the level of its capital and exploration expense expenditures and its future business prospects. A certain financing agreement of the Company contains provisions limiting cash dividends or other distributions to stockholders if aggregate borrowings under such agreement and certain indebtedness of the Company exceeds a certain amount. (See Note 3 to Consolidated Financial Statements).

Item 6. ***Selected Financial Data***

	Year Ended December 31,				
	1991	1990	1989	1988	1987
	(In Thousands, Except Per Share Amounts)				
Statement of Income (Loss) Data:					
Net operating revenues	$ 387,605	$ 371,335	$ 289,416	$ 277,587	$ 268,415
Operating expenses					
Lease and well	49,922	43,806	39,889	46,345	47,965
Exploration	31,470	35,031	23,988	24,143	20,122
Dry hole	14,698	12,986	10,212	14,315	21,949
Impairment of unproved oil and gas properties	12,791	20,571	10,832	21,364	11,109
Depreciation, depletion and amortization	160,885	155,877	134,313	140,512	159,704
General and administrative	36,216	38,254	40,240	42,619	39,087
Taxes other than income	18,222	22,966	23,760	27,918	21,415
Other	-	-	(117)	11,000	-
Total	324,204	329,491	283,117	328,216	321,351
Operating income (loss)	63,401	41,844	6,299	(50,629)	(52,936)
Other income	11,344	28,953	17,441	60,750	18,380
Interest expense (net of interest capitalized)	29,076	36,183	33,225	34,419	34,759
Income (loss) before income taxes	45,669	34,614	(9,485)	(24,298)	(69,315)
Income tax benefit [1]	(9,265)	(10,854)	(3,384)	(8,581)	(28,696)
Net income (loss)	$ 54,934	$ 45,468	$ (6,101)	$ (15,717)	$ (40,619)
Earnings (loss) per share of common stock	$ .72	$ .60	$ (.09)	$ (.25)	$ (.63)
Average number of common shares	75,900	75,900	66,838	64,000	64,000

(Table continued on following page)

	At December 31,				
	1991	1990	1989	1988	1987
	(In Thousands)				
Balance Sheet Data:					
Oil and gas properties – net	$1,339,666	$1,305,136	$1,249,657	$1,222,768	$1,464,421
Total assets	1,455,608	1,417,939	1,365,819	1,308,051	1,570,874
Long-term debt					
Affiliate	132,836	277,918	401,092 [3]	538,397	538,018
Other	289,556	140,442	-	-	-
Stockholders' equity	650,203	610,042	582,321 [3]	377,155 [2]	560,041

(1) Includes a benefit of approximately $17 million in 1991 relating to tight gas sand tax credits and $7 million and $25 million associated with the utilization of a net operating loss carryforward in 1991 and 1990, respectively.

(2) The reduction in 1988 versus 1987 principally reflects the effect of a series of equity transactions resulting in a net return of capital and dividend of $175 million paid by the Company to Enron Corp. which was funded by a portion of proceeds from sales of oil and gas property interests.

(3) The Company completed an initial public offering of 11,500,000 shares of common stock in October 1989 resulting in aggregate net proceeds to the Company of approximately $202 million which were used to repay advances from affiliates.

Item 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

The following review of operations for each of the three years in the period ended December 31, 1991 should be read in conjunction with the consolidated financial statements of the Company and notes thereto beginning with page F-1.

Results of Operations

Net Operating Revenues. Volume and price statistics for the specified years were as follows:

	Year Ended December 31,		
	1991	1990	1989
Wellhead Sales Volumes			
Natural Gas (MMcf per day)	490.6	455.1	344.4
Crude Oil and Condensate (MBbl per day)	8.2	8.2	8.3
Natural Gas Liquids (MBbl per day)	0.6	0.4	0.5
Wellhead Sales Average Prices			
Natural Gas ($/Mcf)	$ 1.37	$ 1.51	$ 1.61
Crude Oil and Condensate ($/Bbl)	18.78	21.67	17.04
Natural Gas Liquids ($/Bbl)	11.64	10.59	9.87
Other Natural Gas Marketing			
Volumes (MMcf per day)	237.2	153.9	67.1
Average Sales Prices ($/Mcf)	$ 2.63	$ 2.90	$ 3.30
Average Purchase Costs ($/Mcf) [1]	1.75	1.99	2.07
Margin ($/Mcf)	$ .88	$ .91	$ 1.23

(1) Including transportation.

During 1991, net operating revenues increased $16 million as compared to 1990 to $388 million.

Average wellhead natural gas sales volumes increased 8% compared to 1990 reflecting the effects of exploration and development activities, as well as the acquisition of properties in the South Texas Lobo Trend and Matagorda Trend areas. Although exploration and development efforts have resulted in significant deliverability increases in the Lobo Trend, Sawyer Canyon and Big Piney areas, these increases were mitigated by curtailments initiated in early 1991 and continuing through most of the remainder of the year, reflecting lower wellhead prices. It is anticipated that these voluntary curtailments which have resumed in early 1992 will continue through most of the remainder of the year. Average wellhead natural gas sales prices were down 9% reflecting continued weakness in the market. Average wellhead crude oil and condensate sales prices were down approximately 13% reflecting a general weakening of worldwide market conditions. The variances in average wellhead sales prices received by the Company reduced net operating revenues by approximately $33 million. The increases in wellhead natural gas sales volumes increased net operating revenues by approximately $20 million.

Other marketing activities associated with sales and purchases of natural gas and crude oil, price swap transactions and commodity price hedging utilizing futures market transactions added $80 million to net operating revenues in 1991, or $29 million more than in 1990. Other natural gas sales volumes, which are primarily with Enron Corp. affiliated companies, increased 54%. This increase primarily reflects deliveries associated with a long-term contract averaging approximately 88 MMcf per day under which initial deliveries commenced in November 1990 and another long-term contract averaging approximately 41 MMcf per day in 1991 with deliveries commencing in April 1991. In addition, deliveries under other miscellaneous long and short-term natural gas marketing arrangements averaged 108 MMcf per day in 1991 compared to 77 MMcf per day in 1990. The average other natural gas marketing sales prices declined $.27 per Mcf, primarily reflecting a blending of sales under the two newer marketing arrangements mentioned above and increased other miscellaneous sales with sales under other preexisting long-term contracts. The cost of purchases to supply these contracts, including transportation, declined $.24 per Mcf, primarily reflecting the impact of a mix of purchases to supply a majority of these sales at lower current market prices. Other crude oil marketing activities added $4 million to net operating revenues in 1991, or $4 million more than in 1990.

During 1990, net operating revenues increased $82 million to $371 million as compared to 1989.

Average wellhead natural gas sales volumes increased just over 32% reflecting the effects of exploration and development activities in Big Piney, South Texas and the Matagorda Trend area as well as the acquisition of additional interests in these core areas. Wellhead crude oil and condensate sales volumes were down 0.1 MBbl per day reflecting the effects of selected property sales in non-core areas which were partially offset by increased volumes from other areas. Average wellhead natural gas sales prices were down approximately 6% primarily reflecting the weaker overall 1990 market and a change in the mix of volumes (increased sales volumes from lower priced fields). However, part of the variance results from the 1989 average wellhead natural gas sales price being favorably impacted by the recognition during 1989 of previously deferred revenues associated with gas balancing. This added approximately $.03 per Mcf to the average sales price for 1989. Average wellhead crude oil and condensate sales prices were up approximately 27% reflecting the impact on world markets of recent developments leading up to the war in the Persian Gulf area. The variances in average wellhead sales prices received by the Company reduced net operating revenues by approximately $3 million. The variances in wellhead sales volumes increased net operating revenues by approximately $65 million.

Other natural gas marketing sales added approximately $51 million to net operating revenues during 1990, or $21 million more than in 1989. Sales volumes under these contracts, which are primarily with a cogeneration facility 50% owned by Enron Corp. and other Enron Corp. affiliated companies, increased 129% reflecting full-year deliveries under two long-term contracts which commenced November 1, 1989. The average other natural gas marketing sales price declined $.40 per Mcf, primarily reflecting a blending of sales under the two newer marketing arrangements mentioned above with sales under other preexisting long-term contracts. The cost of purchases to supply these contracts, including transportation, declined $.08 per Mcf, primarily reflecting a mix of purchases to supply a majority of these sales at current market prices, partially offset by purchases under a long-

term contract with a fixed schedule of prices that are currently above spot-market prices to supply a portion of the preexisting sales.

During 1989, net operating revenues increased $12 million to $289 million as compared to 1988.

Average wellhead natural gas sales prices increased just over 3% during 1989 while average wellhead crude oil and condensate, and natural gas liquids sales prices were up more than 19% and 45%, respectively. Wellhead natural gas sales volumes increased slightly with increased production from the development programs in Big Piney, South Texas and new production from Matagorda Island 604 and 620/638 and the reacquisition of certain producing property interests in conjunction with the termination of certain nonrecourse drilling agreements, more than offsetting the effects of the sales of certain producing property interests in the latter part of 1988 and first half of 1989. Average wellhead crude oil and condensate sales volumes were down 19% primarily reflecting the effects of the sales of certain producing properties noted above. Wellhead natural gas liquid sales volumes declined from 1.4 MBbl per day in 1988 to 0.5 MBbl per day in 1989 primarily reflecting the effects of a new natural gas processing agreement with Northwest Pipeline Corporation executed in the first quarter of 1989 in conjunction with the restructuring of marketing arrangements for natural gas from the Big Piney area. (See "Business — Exploration and Production — Big Piney Area"). The variances in average wellhead sales prices received by the Company in 1989 increased net operating revenues by approximately $15 million. The variances in wellhead sales volumes reduced net operating revenues by approximately $10 million.

Other natural gas marketing sales added approximately $30 million to net operating revenues in 1989, or $5 million more than for the same period in 1988. These sales volumes increased 41% primarily due to deliveries under two long-term contracts which commenced November 1, 1989. (See "Business — Marketing" for a description of these sales and the related purchase arrangements). The average other natural gas marketing sales price declined $.10 per Mcf, primarily reflecting a blending of the two newer marketing arrangements mentioned above with other preexisting long-term contracts. The cost of purchases to supply these contracts, including transportation, increased $.13 per Mcf, primarily reflecting the impact of added purchases at current spot market prices for supplying the new sales during the fourth quarter of 1989 along with the effects of purchases to supply a portion of the preexisting sales which commenced November 1, 1989 under a long-term contract with a fixed schedule of prices above current spot-market prices.

Operating Expenses. During 1991, operating expenses decreased $5 million to $324 million as compared to 1990. Lease and well expenses increased $6 million to $50 million primarily due to expanded operations. Dry hole expenses of $15 million were slightly more than in 1990 primarily reflecting increased drilling activity in areas outside of North America. Impairment of unproved oil and gas properties decreased $8 million to $13 million reflecting reduced impairments of offshore blocks. Depreciation, depletion and amortization ("DD&A") expense was higher in 1991 as compared to 1990 reflecting increased production volumes in 1991 and additional provision for abandonment and site restoration costs mitigated by a decline in the average DD&A rate per Mcfe from $.84 per Mcfe in 1990 to $.81 per Mcfe in 1991. General and administrative expenses decreased $2 million to $36 million primarily reflecting increased costs associated with additional staffing requirements offset by a $4.5 million reduction associated with stock appreciation right ("SAR") unit grants resulting from the effects of lower stock prices more than offsetting the effects of additional vestings. Taxes other than income decreased $5 million primarily due to refunds related to overpayments in prior years and exemptions from Texas severance tax for certain high cost gas production effective September 1, 1991.

During 1990, operating expenses were approximately $329 million or $46 million higher than 1989. Exploration expenses increased almost $11 million to $35 million reflecting increased exploration activities primarily related to international operations. Dry hole expenses increased approximately $3 million in 1990 to $13 million reflecting increased exploratory drilling activities in domestic operations. The increase was mitigated by the absence of international exploratory well costs in areas outside of North America, primarily reflecting the effects of the sale of an additional portion of the Company's working interest in operations in Syria. Impairment of unproved oil and gas properties of almost $21 million was up almost $10 million primarily reflecting additional impairment on certain offshore blocks, two of which expired during the third quarter of 1990. Although DD&A expense increased almost $22 million and lease and well expenses increased approximately $4 million compared to 1989, the Company continued to experience benefits from the sale of selected high cost properties in prior periods and other operating cost efficiencies as reflected by expense rates on an equivalent unit of sales basis. DD&A expense declined from $.93 per Mcfe of sales in 1989 to $.84 per Mcfe in 1990, while lease and well expense declined from $.28 per Mcfe in 1989 to $.24 per Mcfe in 1990.

During 1989, operating expenses declined by more than $45 million, or 14% to $283 million, as compared to 1988. All operating expenses were lower benefiting from the sale of certain high cost producing properties in the latter half of 1988 and first six months of 1989. Increased operating efficiencies also contributed to lease and well expenses declining over $6 million in 1989 as compared to 1988. This reduction was mitigated by production from new properties coming on stream during 1989. Dry hole expenses declined $4 million in 1989 as compared to 1988 largely due to the scaling down and ultimate sale of operations in Ecuador during 1989. The Company drilled one dry hole in Ecuador costing approximately $1 million in 1989 compared to five dry holes charged to expense for over $8 million in 1988. Charges for 1989 included higher dry hole expenses in Canada of approximately $2 million and two dry holes in Syria for more than $2 million. Impairment of unproved oil and gas properties decreased over $10 million in 1989 as compared to 1988 primarily due to the additional impairments taken in 1988 related to selected high cost offshore blocks scheduled to expire in 1989 and 1990. DD&A expense declined over $6 million in 1989 as compared to 1988 benefiting from the sale of certain high cost properties noted above and replacing reserves at lower costs. This reduction in DD&A was mitigated by additional production in 1989 from certain high cost fields. General and administrative expenses in 1989 were down over $2 million as compared to 1988 primarily due to the new general services agreement between the Company and Enron Corp. effective January 1, 1989. (See "Business – Relationship Between the Company and Enron Corp. – Contractual Arrangements"). Such reductions were partially offset in 1989 by a charge of $6.7 million reflecting the one-time cost associated with an employment contract between the Company and the Chairman of the Board, President and Chief Executive Officer and SAR unit accruals of $4.4 million. The $4 million decrease in taxes other than income in 1989 as compared to 1988 was attributable to the change in production mix (greater percentage of sales from offshore properties in 1989) partially offset by increased state tax rates in some western states where the Company does business. Other expenses were down over $11 million in 1989, as compared to 1988. Other expenses for 1988 included a reserve of $4 million to cover estimated costs associated with the planned shut down of certain international operations and a $7 million charge to cover a revaluation of accounts receivable and other similar assets.

Other Income. Other income in 1991 was $11 million as compared to $29 million in 1990. The 1990 period included $32 million in gains on sales of oil and gas properties versus $15 million in 1991.

Other income in 1990 was $29 million, primarily due to gains on sales of oil and gas properties of $32 million, compared to other income of $17 million for 1989. Other income in 1989 included favorable contract reformation and property ownership interest settlements of $6 million in addition to $13 million in gains on sales of oil and gas properties.

Other income of $17 million in 1989 was down approximately $43 million from 1988 due primarily to lower gains on sales of oil and gas properties of $13 million in 1989 as compared to $49 million in 1988.

Interest Expense. Net interest expense decreased $7 million to $29 million in 1991 as compared to 1990 resulting from a restructuring of debt increasing the utilization of short-term and/or floating rate obligations along with the overall reduction in short-term interest rates that occurred during the year. During December 1991 and January 1992 and effective in January 1992, the Company swapped the equivalent of $225 million of floating rate obligations to one to two-year fixed rate obligations with rates averaging approximately 4.9%. Net interest expense increased approximately $3 million in 1990 as compared to 1989 reflecting additional borrowings used to fund increased capital and exploration expense expenditures partially offset by lower interest rates associated with a commercial paper program initiated in early 1990 used to fund current operations and the refinancing of $50 million dollars in long-term debt at floating interest rates during a portion of the year and effectively converted to fixed interest rates with interest rate swap agreements in an equivalent amount in November 1990. Net interest expense decreased approximately $1 million in 1989 reflecting a reduction in interest bearing obligations to Enron Corp.

Income Taxes. Income tax benefit in 1991 and 1990 includes a benefit of approximately $7 million and $25 million, respectively, associated with the utilization of net operating loss carryforwards. Income tax benefit in 1991 also includes a benefit of approximately $16.9 million associated with tight gas sand tax credit utilization and a benefit of $3.5 million related to settlements on audit of tax returns of predecessor companies for the years 1980 through 1983.

On February 10, 1992, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards (SFAS) No. 109 – "Accounting for Income Taxes." The Company is required to adopt the new standard no later than 1993, although earlier implementation is permitted. The change in accounting may be reflected retroactively or through a cumulative adjustment in the year of adoption. The Company is currently analyzing the impact of SFAS No. 109 and, while the effect has not been quantified, the application of SFAS No. 109 is not expected to have a material effect on the financial position or results of operations of the Company.

Capital Resources and Liquidity

Cash Flow. The primary sources of cash for the Company during each of the three years in the period ended December 31, 1991 included funds generated from operations, proceeds from the sale of certain properties, the issuance of new debt and the sale of common stock. Primary cash outflows included funds used in operations, capital and exploration expense expenditures, dividends, and the repayment of debt.

Discretionary cash flow, a frequently used measure of performance for exploration and production companies, is derived by adjusting net income (loss) to eliminate the effects of depreciation, depletion and amortization, impairment of unproved oil and gas properties, deferred taxes, property sales, other miscellaneous non-cash amounts and exploration and dry hole expenses. The Company generated discretionary cash flow of approximately $252 million in 1991, $237 million in 1990 and $165 million in 1989.

Net operating cash flows were approximately $242 million in 1991, $240 million in 1990 and $117 million in 1989. Increased 1991 discretionary cash flow was partially offset by a net increase in working capital requirements, resulting in 1991 net operating cash flows slightly above the 1990 level. Net operating cash flows for 1990 more than doubled when compared to 1989. This increase reflects increased net operating revenues resulting from higher sales volumes, less a related increase in current taxes partially offset by benefits from the utilization of a portion of a net operating loss carryforward available to the Company, plus working capital benefits reflecting the receipt of payment for an income tax receivable under the terms of the Tax Allocation Agreement with Enron Corp., and an increase in cash flow associated with a reduction in working capital requirements year to year. These benefits were partially offset by increased taxes associated with oil and gas property sales in 1990 when compared to 1989. Net operating cash flows in 1989 improved $42 million as compared to 1988 primarily reflecting the less significant effect of the sales of oil and gas properties on income taxes in 1989. (See Note 8 to Consolidated Financial Statements).

Sale of Certain Properties. During 1991, the Company received proceeds of $23 million from the sale of producing and non-producing oil and gas properties. Tax gains resulting from theses sales generated income taxes of $5 million, leaving net proceeds of $18 million. In 1990, the Company received proceeds of $57 million from the sale of producing and non-producing oil and gas properties. Tax gains resulting from these sales generated income taxes of $15 million, leaving net proceeds of $42 million. During 1988 and 1989, the Company sold certain producing and nonproducing oil and gas property interests in a series of transactions. The aggregate proceeds received totaled $282 million in 1988 and $35 million in 1989. In 1988 and 1989, tax gains resulting from the sales generated income tax burdens of $68 million and $7 million, respectively, leaving net proceeds after income taxes of approximately $214 million in 1988 and $28 million in 1989.

Sale of Common Stock. In October 1989, the Company completed an initial public offering of 11.5 million shares of Common Stock. The shares were priced to the public at $18.75 per share. Net proceeds after underwriting commissions and expenses totaled approximately $202 million and were used primarily to repay advances from affiliates. Enron Corp. retained ownership of approximately 84% of the Company.

Capital and Exploration Expense Expenditures. The table below sets out components of actual capital and exploration expense expenditures for the years ended 1991, 1990 and 1989, along with those budgeted for the year 1992.

Expenditure Category	Actual 1991	1990	1989	Budgeted 1992
		(In Millions)		
Capital				
Drilling and Facilities	$149.3	$138.3	$128.9	$147.0
Leasehold Acquisitions	12.6	49.6	31.1	13.0
Producing Property Acquisitions	42.4	59.9	31.2	38.0
Capitalized Interest and Other	7.4	13.1	8.2	12.0
Total	211.7	260.9	199.4	210.0
Exploration Expenses	46.1	48.0	34.2	40.0
Total	$257.8	$308.9	$233.6	$250.0

Total capital and exploration expense expenditures decreased $51 million or 17% in 1991 compared to 1990. The decrease was the result of a reduction in expenditures for acquisitions of undeveloped leasehold and producing properties. However, the Company increased its development expenditures focusing on tight gas sand drilling in core areas. Capital and exploration expense expenditures increased approximately $75 million or 32% to $309 million in 1990 from approximately $234 million in 1989. The significant increase was attributable primarily to drilling and facilities, and undeveloped leasehold and producing property acquisition activities in core areas. Undeveloped leasehold acquisitions of $49.6 million included a $23.8 million payment to Taylor Energy Company as an adjustment of the purchase price for the acquisition by the Company of a 91.9% working interest in a portion of Matagorda Island Block 620 pursuant to an agreement entered into during 1989. The initial purchase price paid by the Company for such leasehold interest was $14.7 million. There is no provision for any further adjustment of the purchase price with respect to sand lobes determined to contain proved reserves at December 31, 1989. However, the agreement does provide for possible subsequent upward adjustment of the purchase price with respect to other sand lobes should any subsequently be determined to contain proved reserves. The 1989 capital and exploration expense expenditures of approximately $234 million increased by $63 million over 1988 primarily due to an increase of more than $77 million in drilling and facility expenditures. (See "Business – Exploration and Production" for additional information detailing the specific geographic locations of the related drilling programs and "Outlook" below for a discussion related to 1992 capital and exploration expense expenditure plans).

Financing. Concurrent with the closing of the initial public offering in October 1989, the Company entered into a new senior note agreement with Enron Corp. in the amount of $360 million bearing interest at the rate of 10% per annum, with nine annual principal repayments commencing on October 12, 1992. All previous advances from Enron Corp. not refinanced with the new senior note were repaid with the net proceeds from the offering. Prepayments of $285 million were subsequently made on the senior note and, in May 1991, the $75 million remaining balance was refinanced by the Company with the execution of a promissory note payable to Enron Corp. with a variable rate of interest based on the London Interbank Offered Rate and final maturities ending in 1996. The Company has entered into reciprocal financing arrangements with Enron Corp. pursuant to which the Company may borrow funds from or, at its discretion, advance funds to, Enron Corp. at representative market rates of interest. Daily outstanding balances of funds borrowed by the Company averaged $3 million during 1991 with a balance of $58 million at December 31, 1991. Daily outstanding balances of funds advanced to Enron Corp. averaged $4 million during 1991 with no advances outstanding at December 31, 1991. Balances outstanding under the commercial paper program initiated in 1990 increased $39 million to $130 million at December 31, 1991. The proceeds from the commercial paper program are being used to fund current transactions. In February 1991, the Company completed a $100 million private placement sale of senior notes with final maturities ending in 1998, proceeds from which were used to prepay an equal amount of the senior note due Enron Corp. During 1991, total long-term debt increased $4 million to $422 million. The Company's debt-to-total-capital ratio was 39%, 41% and 41% as of December 31, 1991, 1990 and 1989, respectively.

Outlook. In looking ahead, four key factors are expected to have a significant impact on Company strategies for the coming year. First, the results of another warmer than historical winter in the United States and current natural gas price trends suggest that natural gas prices for the year may continue to lag behind parity with crude oil and condensate, possibly remaining below last year's average levels. However, management believes that continually increasing recognition of natural gas as a more environmentally friendly source of energy along with the availability of significant domestically sourced supplies will result in further increases in demand and a strengthening of the overall natural gas market over time. Being primarily a natural gas producer, the Company is more significantly impacted by changes in natural gas prices than by changes in crude oil and condensate prices. (See "Business – Other Matters – Energy Prices"). Excluding the effects of short-term price hedging using the futures market, the Company's current net income sensitivity to changing natural gas prices is approximately $8.5 million for each $.10/Mcf change in average wellhead natural gas prices.

The other three factors represent positive near-term impacts. They include the federal income tax credit available on certain tight formation natural gas sales volumes, the Texas severance tax exemption available on certain high cost natural gas revenues and benefits being realized in the current environment from other natural gas marketing activities. (See "Business – Other Matters – Tight Gas Sands Tax Credit (Section 29) and Severance Tax Exemption" and "Business – Marketing"). These three factors are expected to contribute significantly to both earnings and cash flow for 1992, supporting the ability of the Company to pursue the continuation of an active development and acquisition program despite possible continued deterioration of the natural gas market.

The Company will continue to focus development and limited exploration expenditures in its core and other major producing areas, and include limited but meaningful exploratory exposure in areas outside of North America. (See "Business – Exploration and Production" for additional information detailing the specific geographic locations of the related drilling programs). Early-in-year activity will be managed within an annual expected expenditure level of approximately $250 million. This early-in-year planning addresses the possibility of continued constraint on the availability of cash caused primarily by the current indications of a soft natural gas market and price environment for the year, and the Company strategy of funding exploration, development and acquisition activities primarily from available internally generated cash flow. Expenditure plans for 1992 will be focused toward optimizing the development of natural gas reserves that are qualified for the tight formation natural gas federal income tax credit, acquisitions of proved reserves in core areas, and an increased emphasis on developing oil reserves.

The level of capital and exploration expense expenditures may vary in 1992 and will vary in future periods depending on energy market conditions and other related economic factors. Based upon existing economic and market conditions, the Company believes net operating cash flow and available financing alternatives in 1992 will be sufficient to fund its net investing cash requirements for the year. However, the Company has significant flexibility with respect to its financing alternatives and adjustment of its capital and exploration expense expenditure plans as circumstances warrant. There are no material continuing commitments associated with expenditure plans.

Item 8. ***Financial Statements and Supplementary Data***

The information required hereunder is included in this report as set forth in the "Index to Financial Statements" on page F-1.

Item 9. ***Disagreements on Accounting and Financial Disclosure***

None.

PART III

Item 10. ***Directors and Executive Officers of the Registrant***

The information required by this Item regarding directors is set forth in the Proxy Statement under the caption entitled "Election of Directors", and is incorporated herein by reference.

See list of "Current Executive Officers of the Registrant" in Part I located elsewhere herein.

There are no family relationships among the officers listed, and there are no arrangements or understandings pursuant to which any of them were elected as officers. Officers are appointed or elected annually by the Board of Directors at its first meeting following the Annual Meeting of Stockholders, each to hold office until the corresponding meeting of the Board in the next year or until a successor shall have been elected, appointed or shall have qualified.

Item 11. ***Executive Compensation***

The information required by this Item is set forth in the Proxy Statement under the caption "Compensation of Directors and Executive Officers", and is incorporated herein by reference.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management***

The information required by this Item is set forth in the Proxy Statement under the captions "Election of Directors" and "Compensation of Directors and Executive Officers", and is incorporated herein by reference.

Item 13. ***Certain Relationships and Related Transactions***

The information required by this Item is set forth in the Proxy Statement under the caption "Certain Transactions", and is incorporated herein by reference.

PART IV

Item 14. ***Exhibits, Financial Statement Schedules, and Reports on Form 8-K***

(a)(1) and (2) Financial Statements and Financial Statement Schedules

See "Index to Financial Statements" set forth on page F-1.

(a)(3) Exhibits

See pages E-1 through E-2 for a listing of the exhibits.

(b) Reports on Form 8-K

No reports on Form 8-K were filed by the Company during the last quarter of 1991.

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Other financial statement schedules have been omitted because they are inapplicable or the information required therein is included elsewhere in the consolidated financial statements or notes thereto.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To Enron Oil & Gas Company:

We have audited the accompanying consolidated balance sheets of Enron Oil & Gas Company (a Delaware corporation) and subsidiaries as of December 31, 1991 and 1990, and the related consolidated statements of income (loss), stockholders' equity and cash flows for each of the three years in the period ended December 31, 1991. These financial statements and the schedules referred to below are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedules based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Enron Oil & Gas Company and subsidiaries as of December 31, 1991 and 1990, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1991, in conformity with generally accepted accounting principles.

Our audits were made for the purpose of forming an opinion on the basic financial statements taken as a whole. The financial statement schedules listed in the index to financial statements are presented for purposes of complying with the Securities and Exchange Commission's rules and are not part of the basic financial statements. These schedules have been subjected to the auditing procedures applied in the audits of the basic financial statements and, in our opinion, fairly state in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

ARTHUR ANDERSEN & CO.

Houston, Texas
February 11, 1992

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The following consolidated financial statements of Enron Oil & Gas Company and its subsidiaries were prepared by management which is responsible for their integrity, objectivity and fair presentation. The statements have been prepared in conformity with generally accepted accounting principles and accordingly include some amounts that are based on the best estimates and judgements of management.

Arthur Andersen & Co., independent public accountants, was engaged to audit the consolidated financial statements of Enron Oil & Gas Company and its subsidiaries and issue a report thereon. In the conduct of the audit, Arthur Andersen & Co. was given unrestricted access to all financial records and related data including minutes of all meetings of stockholders, the Board of Directors and committees of the Board. Management believes that all representations made to Arthur Andersen & Co. during the audit were valid and appropriate. Their audits of the years presented included developing an overall understanding of the Company's accounting systems, procedures and internal controls, and conducting tests and other auditing procedures sufficient to support their opinion on the financial statements. The report of Arthur Andersen & Co. appears on the preceding page.

The system of internal controls of Enron Oil & Gas Company and its subsidiaries is designed to provide reasonable assurance as to the reliability of financial records as represented in published interim and annual financial statements. This system includes, but is not limited to, written policies and guidelines including a published code for the conduct of business affairs, a strong program of internal audit, the careful selection and training of qualified personnel, and a documented organizational structure outlining the separation of responsibilities among management representatives and staff groups.

The adequacy of financial controls of Enron Oil & Gas Company and its subsidiaries and the accounting principles employed in financial reporting by the Company are under the general oversight of the Audit Committee of the Board of Directors. No member of this committee is an officer or employee of the Company. Both the independent public accountants and internal auditors have direct access to the Audit Committee and meet with the committee from time to time to discuss accounting, auditing and financial reporting matters.

It should be recognized that there are inherent limitations to the effectiveness of any system of internal control, including the possibility of human error and circumvention or override. Accordingly, even an effective system can provide only reasonable assurance with respect to the preparation of reliable financial statements. Furthermore, the effectiveness of an internal control system can change with circumstances.

It is management's opinion that, considering the criteria for effective internal control over financial reporting which consists of interrelated components including the control environment, risk-assessment process, control activities, information and communication systems, and monitoring, the Company maintained an effective system of internal control over the preparation of published interim and annual financial statements for all periods presented.

BEN B. BOYD Vice President and Controller	WALTER C. WILSON Senior Vice President and Chief Financial Officer	FORREST E. HOGLUND Chairman of the Board, President and Chief Executive Officer

Houston, Texas
March 20, 1992

ENRON OIL & GAS COMPANY
CONSOLIDATED STATEMENTS OF INCOME (LOSS)
(In Thousands Except Per Share Amounts)

	Year Ended December 31, 1991	1990	1989
NET OPERATING REVENUES			
Natural Gas			
Associated Companies	$275,362	$209,361	$141,287
Trade	46,241	92,284	90,906
Crude Oil, Condensate and Natural Gas Liquids			
Associated Companies	41,237	43,693	29,757
Trade	21,599	22,472	22,916
Other	3,166	3,525	4,550
Total	387,605	371,335	289,416
OPERATING EXPENSES			
Lease and Well	49,922	43,806	39,889
Exploration	31,470	35,031	23,988
Dry Hole	14,698	12,986	10,212
Impairment of Unproved Oil and Gas Properties	12,791	20,571	10,832
Depreciation, Depletion and Amortization	160,885	155,877	134,313
General and Administrative	36,216	38,254	40,240
Taxes Other Than Income	18,222	22,966	23,760
Other	–	–	(117)
Total	324,204	329,491	283,117
OPERATING INCOME	63,401	41,844	6,299
OTHER INCOME	11,344	28,953	17,441
INCOME BEFORE INTEREST EXPENSE AND TAXES	74,745	70,797	23,740
INTEREST EXPENSE			
Incurred			
Affiliate	9,233	28,332	36,614
Other	24,325	12,294	1,179
Capitalized	(4,482)	(4,443)	(4,568)
Net Interest Expense	29,076	36,183	33,225
INCOME (LOSS) BEFORE INCOME TAXES	45,669	34,614	(9,485)
INCOME TAX BENEFIT	(9,265)	(10,854)	(3,384)
NET INCOME (LOSS)	$ 54,934	$ 45,468	$ (6,101)
EARNINGS (LOSS) PER SHARE OF COMMON STOCK	$ .72	$ .60	$ (.09)
AVERAGE NUMBER OF COMMON SHARES	75,900	75,900	66,838

The accompanying notes are an integral part of these consolidated financial statements.

ENRON OIL & GAS COMPANY
CONSOLIDATED BALANCE SHEETS
(In Thousands)

	At December 31, 1991	1990
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3,799	$ 3,595
Accounts Receivable		
Associated Companies	56,070	50,576
Trade	33,468	40,741
Inventories	13,221	13,202
Other	3,148	2,868
Total	109,706	110,982
OIL AND GAS PROPERTIES (Successful Efforts Method)	2,228,634	2,065,999
Less: Accumulated Depreciation, Depletion and Amortization	888,968	760,863
Net Oil and Gas Properties	1,339,666	1,305,136
OTHER ASSETS	6,236	1,821
TOTAL ASSETS	$1,455,608	$1,417,939
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts Payable		
Associated Companies	$ 10,610	$ 19,911
Trade	73,647	64,361
Accrued Taxes Payable	9,664	8,653
Dividends Payable	3,795	3,795
Other	15,595	13,264
Total	113,311	109,984
LONG-TERM DEBT		
Affiliate	132,836	277,918
Other	289,556	140,442
DEFERRED INCOME TAXES	260,294	276,070
OTHER LIABILITIES	9,408	3,483
STOCKHOLDERS' EQUITY		
Preferred Stock, $1 Par, 10,000,000 Shares Authorized, No Shares Issued and Outstanding	–	–
Common Stock, No Par, 100,000,000 Shares Authorized, 75,900,000 Shares Issued and Outstanding	200,759	200,759
Additional Paid In Capital	310,504	310,504
Cumulative Foreign Currency Translation Adjustment	6,947	6,540
Retained Earnings	131,993	92,239
Total Stockholders' Equity	650,203	610,042
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$1,455,608	$1,417,939

The accompanying notes are an integral part of these consolidated financial statements.

ENRON OIL & GAS COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(In Thousands Except Per Share Amounts)

	Common Stock	Additional Paid In Capital	Cumulative Foreign Currency Translation Adjustment	Retained Earnings	Total Stockholders' Equity
Balance at December 31, 1988	$ 640	$ 298,973	$ 5,695	$ 71,847	$ 377,155
Net Loss	-	-	-	(6,101)	(6,101)
Contribution from Stockholder	-	5,000	-	-	5,000
Shares Issued to Officer	4	4,396	-	-	4,400
Shares Issued by Public Offering	115	202,135	-	-	202,250
Transfer of Capital	200,000	(200,000)	-	-	-
Dividend Declared, $.05 Per Share	-	-	-	(3,795)	(3,795)
Translation Adjustment	-	-	3,412	-	3,412
Balance at December 31, 1989	200,759	310,504	9,107	61,951	582,321
Net Income	-	-	-	45,468	45,468
Dividends Paid/Declared, $.20 Per Share	-	-	-	(15,180)	(15,180)
Translation Adjustment	-	-	(2,567)	-	(2,567)
Balance at December 31, 1990	200,759	310,504	6,540	92,239	610,042
Net Income	-	-	-	54,934	54,934
Dividends Paid/Declared, $.20 Per Share	-	-	-	(15,180)	(15,180)
Translation Adjustment	-	-	407	-	407
Balance at December 31, 1991	$200,759	$ 310,504	$ 6,947	$131,993	$ 650,203

The accompanying notes are an integral part of these consolidated financial statements.

ENRON OIL & GAS COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In Thousands)

	Year Ended December 31, 1991	1990	1989
CASH FLOWS FROM OPERATING ACTIVITIES			
Reconciliation of Net Income (Loss) to Net Operating Cash Inflows:			
Net Income (Loss)	$ 54,934	$ 45,468	$ (6,101)
Items Not Requiring (Providing) Cash			
Depreciation, Depletion and Amortization	160,885	155,877	134,313
Impairment of Unproved Oil and Gas Properties	12,791	20,571	10,832
Deferred Income Taxes	(19,015)	(21,728)	12,727
Other, Net	5,073	10,597	(1,950)
Exploration Expenses	31,470	35,031	23,988
Dry Hole Expenses	14,698	12,986	10,212
Gains On Sales of Oil and Gas Properties	(14,983)	(31,802)	(12,656)
Other, Net	614	(5,187)	(13,056)
Changes in Components of Working Capital and Other Liabilities			
Accounts Receivable	(821)	(12,562)	(25,889)
Inventories	(19)	2,022	(4,003)
Receivable for Taxes	-	-	2,540
Accounts Payable	381	23,096	2,088
Accrued Taxes Payable	1,011	123	(442)
Other Liabilities	(1,006)	707	(11,507)
Other, Net	3,839	3,163	4,468
Changes in Components of Working Capital Associated with Investing Activities	(7,976)	1,251	(8,379)
NET OPERATING CASH INFLOWS	241,876	239,613	117,185
INVESTING CASH FLOWS			
Additions to Oil and Gas Properties	(211,673)	(260,860)	(199,354)
Exploration Expenses	(31,470)	(35,031)	(23,988)
Dry Hole Expenses	(14,698)	(12,986)	(10,212)
Proceeds from Property Sales	22,827	56,706	35,110
Changes in Components of Working Capital Associated with Investing Activities	7,976	(1,251)	8,379
Other, Net	(3,549)	195	324
NET INVESTING CASH OUTFLOWS	(230,587)	(253,227)	(189,741)
FINANCING CASH FLOWS			
Long-Term Debt			
Affiliate	(145,082)	(123,174)	(137,305)
Other	149,114	140,442	-
Contribution from Stockholder	-	-	5,000
Common Stock Issued	-	-	206,650
Dividends Paid	(15,180)	(15,180)	-
Other, Net	63	(205)	13,274
NET FINANCING CASH INFLOWS (OUTFLOWS)	(11,085)	1,883	87,619
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	204	(11,731)	15,063
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	3,595	15,326	263
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 3,799	$ 3,595	$ 15,326

The accompanying notes are an integral part of these consolidated financial statements.

ENRON OIL & GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(In Thousands Unless Otherwise Indicated)

1. Summary of Significant Accounting Policies

Principles of Consolidation. The consolidated financial statements of Enron Oil & Gas Company (the "Company"), 84.3% of the outstanding common stock of which is owned by Enron Corp., include the accounts of all domestic and foreign subsidiaries. All material intercompany accounts and transactions have been eliminated. Certain reclassifications have been made to prior years' consolidated financial statements to conform with the current presentation.

Cash Equivalents. The Company records as cash equivalents all highly liquid short-term investments with maturities of three months or less.

Oil and Gas Operations. The Company accounts for its natural gas and crude oil exploration and production activities under the successful efforts method of accounting.

Oil and gas lease acquisition costs are capitalized when incurred. Unproved properties with significant acquisition costs are assessed quarterly on a property-by-property basis and any impairment in value is recognized. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive, based on historical experience, is amortized over the average holding period. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved oil and gas properties. Lease rentals are expensed as incurred.

Oil and gas exploration costs, other than the costs of drilling exploratory wells, are charged to expense as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether they have discovered proved commercial reserves. If proved commercial reserves are not discovered, such drilling costs are expensed. The costs of all development wells and related equipment used in the production of crude oil and natural gas are capitalized.

Depreciation, depletion and amortization of the cost of proved oil and gas properties is calculated using the unit-of-production method. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account. Certain other assets are depreciated on a straight-line basis.

Inventories, consisting primarily of tubular goods and well equipment held for use in the exploration for, and development and production of crude oil and natural gas reserves, are carried at cost with selected adjustments made from time to time to recognize changes in condition value.

Natural gas revenues are recorded to recognize that during the course of normal production operations joint interest owners will, from time to time, take more or less than their share of natural gas volumes from jointly owned reservoirs. These volumetric imbalances are monitored over the life of the reservoir to achieve balancing, or minimize imbalances, by the time reserves are depleted. Final cash settlements are made, generally at the time a property is depleted, under one of a variety of arrangements generally accepted by the industry depending on the specific circumstances involved. The Company accrues values associated with undertakes and defers values associated with overtakes to recognize these imbalances.

Accounting for Futures Contracts. Futures transactions are entered into primarily to hedge contracts to buy and sell crude oil and natural gas, in order to minimize the risk of market fluctuations. Changes in the market value of futures transactions entered into as hedges are deferred until the gain or loss is recognized on the hedged transactions.

Capitalized Interest Costs. Certain interest costs have been capitalized as a part of the historical cost of unproved oil and gas properties. Interest costs capitalized during each of the three years in the period ended December 31, 1991 are set out in the Consolidated Statements of Income (Loss).

Income Taxes. Taxable income of the Company, excluding that of any foreign subsidiaries, is included in the consolidated federal income tax return filed by Enron Corp. Pursuant to a tax allocation agreement with Enron Corp., the provision for (benefit from) income taxes is calculated as if the Company filed a separate federal income tax return but may include benefits from deductions and tax credits that are realizable only on a consolidated basis. In 1991, the Company and Enron Corp. modified the tax allocation agreement to provide that through 1992, the Company will realize the benefit of certain tight gas sand tax credits available to the Company on a stand alone basis. The Company has also entered into an agreement with Enron Corp. providing for the Company to be paid for all realizable benefits associated with tight gas sand tax credits concurrent with tax reporting and settlement for the periods in which they are generated. Taxes for any foreign subsidiaries of the Company are calculated on a separate return basis.

The Company accounts for income taxes under the provisions of Statement of Financial Accounting Standards (SFAS) No. 96 – "Accounting for Income Taxes". Deferred income taxes have been provided for all differences in the bases of assets and liabilities for tax and financial reporting purposes.

Foreign Currency Translation. Presently, Canadian operations represent substantially all foreign activities of the Company and the Canadian dollar is considered the functional currency. The functional currency financial statements are translated into U.S. dollars using current exchange rates, and resulting translation gains and losses, which do not impact cash flows, are accumulated as a separate component of Stockholders' Equity.

Earnings Per Share. Earnings per share is computed on the basis of the average number of common shares outstanding during the periods.

2. Natural Gas and Crude Oil, Condensate and Natural Gas Liquids Net Operating Revenues

Natural Gas Net Operating Revenues are comprised of the following:

	1991	1990	1989
Wellhead Natural Gas Sales			
Associated Companies(1)	$171,056	$146,901	$111,853
Trade	75,037	103,506	90,178
Total	$246,093	$250,407	$202,031
Other Natural Gas Marketing Activities			
Sales to:			
Associated Companies	$220,152(2)	$157,627	$ 77,610
Trade	7,215	5,546	3,166
Total	227,367	163,173	80,776
Purchase Costs from:			
Associated Companies(1)	115,601(3)	95,167(3)	48,176
Trade	36,011	16,768	2,438
Total	151,612	111,935	50,614
Net	75,755	51,238	30,162
Commodity Price Hedging Loss(4)	(245)	–	–
Total	$ 75,510	$ 51,238	$ 30,162

(Footnotes on following page)

Crude Oil, Condensate and Natural Gas Liquids Net Operating Revenues are comprised of the following:

	1991	1990	1989
Wellhead Crude Oil, Condensate and Natural Gas Liquid Sales			
Associated Companies	$37,029	$43,913	$30,173
Trade	21,599	22,472	22,916
Total	$58,628	$66,385	$53,089
Other Crude Oil Marketing Activities			
Commodity Price Hedging Gain (Loss)(4)	$ 4,208	$ (220)	$ (416)

(1) Wellhead Natural Gas Sales in 1991, 1990 and 1989 include $69,175, $49,332 and $7,030, respectively, of sales by Enron Oil & Gas Company to Enron Oil & Gas Marketing, Inc. ("EOGM"), a wholly-owned subsidiary, reflected as a cost in Natural Gas Purchase Costs.

(2) Includes the effect of a price swap agreement with an Enron Corp. affiliated company which effectively fixes the price of certain sales.

(3) Includes the effect of a price swap agreement with a third party which fixes the price of certain purchases.

(4) Represents futures transactions with Enron Corp. affiliated companies.

3. Long-Term Debt

Credit Agreement. The Company is a party to a Credit Agreement dated as of December 4, 1990, among the Company and the banks named therein (the "Credit Agreement"). As of December 31, 1991, the Credit Agreement provided for aggregate borrowings of up to $300 million, subject to certain borrowing base limitations relating to the value of interests in certain oil and gas properties of the Company and its subsidiaries. The borrowing availability under the Credit Agreement is subject to reduction at the option of the Company and to mandatory quarterly reductions beginning in March 1994. At December 31, 1991 the borrowing base was $600 million. Loans under the Credit Agreement bear interest, at the option of the Company, based on a base rate, an adjusted CD rate or a Eurodollar rate, plus a varying amount of up to .45%. In addition, loans may bear interest at a rate determined pursuant to an auction bidding procedure. Each advance under the Credit Agreement matures on a date selected by the Company at the time of the advance, but in no event after December 31, 1994.

The Credit Agreement contains affirmative and negative covenants, including maintenance of certain financial ratios and, subject to certain exceptions, prohibitions of liens on, or sales, leases or other dispositions of properties, and of cash dividends or other distributions to stockholders if the aggregate borrowings under the Credit Agreement and certain indebtedness of the Company and its subsidiaries (excluding intercompany indebtedness and certain subordinated debt) exceed the borrowing base under the Credit Agreement. There were no advances outstanding under the Credit Agreement at December 31, 1991.

Financing Arrangements with Enron Corp. The Company engages in various transactions with Enron Corp. that are characteristic of a consolidated group under common control. Activities of the Company not internally funded from operations have been and may be funded by advances from Enron Corp. Prior to the closing of an initial public offering of 11,500,000 shares of common stock of the Company on October 12, 1989, interest expense was charged by Enron Corp. on a portion of the advances covered by a long-term note, which note was converted to a subordinated note effective December 31, 1988, at an interest rate of 10%. Interest charged by Enron Corp. for the subordinated note totaled $28.6 million in 1989. The portion of the advances which were interest bearing averaged $365.0 million in 1989, as compared to total advances which averaged $554.0 million for the same period. Concurrent with the closing of the initial public offering, the Company entered into a new senior note agreement with Enron Corp. in the amount of $360 million and bearing interest at the

rate of 10%, with nine annual principal repayments commencing on October 12, 1992. All previous advances not refinanced with the new senior note were repaid with the net proceeds from the offering. Prepayments of $285 million were subsequently made on the senior note and, in May 1991, the $75 million remaining balance was refinanced by the Company with the execution of a promissory note payable to Enron Corp. with a variable rate of interest based on the London Interbank Offered Rate with a rate at December 31, 1991 of 4.6% and with three annual principal repayments of $25 million each commencing on May 1, 1994. Interest expense recorded in 1991, 1990 and 1989 for the senior note totaled $6.4, $27.6 and $7.8 million, respectively. Interest expense recorded in 1991 for the promissory note totaled $2.9 million.

The Company also entered into an agreement with Enron Corp. effective October 12, 1989 under which the Company may borrow funds from Enron Corp. at a representative market rate of interest on a revolving basis with a rate at December 31, 1991 of 4.3%. Daily outstanding balances of funds borrowed by the Company under this agreement averaged $2.9 million during 1991 with a balance of $57.8 million at December 31, 1991. Any loan balance that may be outstanding from time to time is payable on demand but no later than October 12, 1992, the maturity date of this agreement. The liability is classified as long-term based on the Company's intent and ability to refinance such amount using available borrowing capacity. Interest expense recorded in 1991, 1990 and 1989 under the terms of this agreement totaled $172,000, $952,000 and $244,000, respectively.

The Company also entered into an agreement with Enron Corp. effective October 12, 1989 which provides the Company the option of advancing any excess funds that may be available from time to time to Enron Corp. Enron Corp., under the terms of the agreement, will pay the Company interest at a representative market rate during the periods the funds are held by Enron Corp. The interest rate to be paid the Company is determined using a mechanism identical to that which determines the interest to be paid on funds borrowed from Enron Corp. on a revolving basis. Daily outstanding balances of funds advanced to Enron Corp. under this agreement averaged $4.3 million during 1991 with no advances outstanding at December 31, 1991. Interest income recorded in 1991, 1990 and 1989 under the terms of this agreement totaled $270,000, $187,000 and $21,000, respectively.

Long-Term Debt, Other. Long-Term Debt, Other at December 31 consisted of the following:

	1991	1990
Commercial Paper	$129,556	$ 90,442
Loans Payable	50,000	50,000
Senior Notes	100,000	–
Bank Borrowings	10,000	–
Total	$289,556	$140,442

Commercial Paper and Bank Borrowings were issued at prevailing market interest rates. These liabilities are classified as long-term based on the Company's intent and ability to refinance such amounts using available borrowing capacity. Proceeds from the commercial paper program and bank borrowings are used to fund current transactions. The weighted average interest rate for these obligations at December 31, 1991 was 5.6%.

The Loans Payable are due in 1995 and bear interest at a variable rate based on the London Interbank Offered Rate which has, in effect, been converted to fixed interest rates ranging from 8.48% to 8.98% through maturity using interest rate swap agreements in equivalent dollar amounts. The proceeds from this debt were used to prepay a portion of long-term debt due Enron Corp.

The Senior Notes bear interest at 9.1% with principal repayments of $30 million due in 1994 and 1996 and $20 million due in 1997 and 1998. The proceeds of these notes were used to prepay a portion of long-term debt due Enron Corp.

Certain of the borrowings described above contain covenants requiring the maintenance of certain financial ratios and limitations on liens, debt issuance and dispositions of assets.

In September 1991, the Company filed with the Securities and Exchange Commission a registration statement providing for the issuance from time to time of up to $250 million of debt securities to the public. As of March 1, 1992, no debt securities had been issued under this registration statement.

In December 1991 and Janurary 1992 and effective in January 1992, the Company entered into interest rate swap agreements with third parties in notional amounts totaling $225 million which had the effect of fixing the interest rates on an equivalent dollar amount of floating rate obligations for one to two years. The fixed rates average approximately 4.9%.

4. Stockholders' Equity

In July 1989, the Company issued to an officer 400,000 shares of its common stock valued at $11.00 per share at the time of grant. (See Note 7 "Commitments and Contingencies - Enron Oil & Gas Company Executive Compensation Plan").

During October 1989, the Company completed an initial public offering of 11.5 million shares of common stock. The shares were priced to the public at $18.75 per share. Net proceeds after underwriting commissions and expenses totaled approximately $202 million and were used primarily to repay advances from affiliates. Enron Corp. retained ownership of approximately 84.3% of the Company.

In October 1989, the Board of Directors of the Company approved the transfer of $200 million from Additional Paid In Capital to Common Stock.

5. Transactions with Enron Corp. and Related Parties

Natural Gas, Crude Oil and Condensate, and Natural Gas Liquids Net Operating Revenues. Wellhead Natural Gas and Crude Oil, Condensate and Natural Gas Liquids Sales and Other Natural Gas and Crude Oil Marketing Activities include sales to and purchases from various subsidiaries and affiliates of Enron Corp. pursuant to contracts which, in the opinion of management, are no less favorable than could be obtained from third parties. Other Natural Gas and Crude Oil Marketing Activities also include certain price swap and futures transactions with Enron Corp. affiliate companies. See Note 2 "Natural Gas and Crude Oil, Condensate and Natural Gas Liquids Net Operating Revenues".

General and Administrative Expenses. The Company is charged by Enron Corp. for all direct costs associated with its operations. Such direct charges, excluding benefit plan charges (See Note 7 "Commitments and Contingencies – Employee Benefit Plans"), totaled $7.4 million, $8.1 million and $8.0 million for the years ended December 31, 1991, 1990 and 1989, respectively. Management believes that these charges are reasonable.

Additionally, certain administrative costs not directly charged to any Enron Corp. operations or business segments are allocated to the entities of the consolidated group. Allocation percentages are generally determined utilizing weighted average factors derived from property gross book value, revenue less certain operating expenses and payroll costs. Effective January 1, 1989, the Company entered into an agreement with Enron Corp., with an initial term of five years, providing for, among other things, an annual cap of $8.0 million to be applied to indirect allocated charges subject to adjustment for inflation and certain changes in the allocation bases of the Company. Approximately $9.4 million, $8.6 million and $8.0 million were charged to the Company for indirect general and administrative expenses for the years ended December 31, 1991, 1990 and 1989, respectively. Management believes the indirect allocated charges for the numerous types of support services provided by the corporate staff are reasonable.

Financing. See Note 3 "Long-Term Debt" for a discussion of financing arrangements with Enron Corp.

6. Income Taxes

The components of income (loss) before income taxes were as follows:

	1991	1990	1989
United States	$ 49,187	$ 33,008	$ (11,439)
Foreign	(3,518)	1,606	1,954
Total	$ 45,669	$ 34,614	$ (9,485)

Total income taxes (benefits) were as follows:

	1991	1990	1989
Current:			
Federal	$ 9,226	$ 10,588	$ (16,798)
State	-	-	396
Foreign	524	286	291
Total	9,750	10,874	(16,111)
Deferred:			
Federal	(20,301)	(24,457)	13,116
State	1,328	1,600	-
Foreign	(42)	1,129	(389)
Total	(19,015)	(21,728)	12,727
Income Tax Benefit	$ (9,265)	$ (10,854)	$ (3,384)

The differences between the U.S. Federal income tax rate and the Company's effective income tax rate were caused primarily by permanent book and federal income tax differences as follows:

	1991	1990	1989
Statutory Federal Income Tax (Benefit)	$ 15,528	$ 11,768	$ (3,225)
State and Foreign Income Tax (Benefit)	2,554	1,836	(558)
Amortization of Permanent Differences Resulting from Acquisitions	-	-	298
Tight Gas Sand Tax Credits	(16,926)	-	-
Foreign Tax Credit	(339)	-	-
Net Operating Loss Utilization	(6,656)	(24,498)	-
Tax Audit Settlement	(3,466)	-	-
Other	40	40	101
Income Tax Benefit	$ (9,265)	$ (10,854)	$ (3,384)

Deferred taxes result from changes in differences in the bases of assets and liabilities for tax and financial reporting purposes as follows:

	1991	1990	1989
Exploration and Development Costs	$ 1,107	$ 7,074	$ 24,447
Depreciation, Depletion and Amortization	(27,300)	(30,206)	(25,379)
Surrendered and Expired Leases	245	2,381	15,669
Capitalized Interest	1,186	1,170	1,534
Financial Reserves	(396)	4,563	2,095
Property Sales	(104)	(3,567)	1,362
Net Operating Loss Carryforward	10,218	(2,792)	(7,412)
Tax Audit Settlement	(3,466)	-	-
Other	(505)	(351)	411
Total	$ (19,015)	$ (21,728)	$ 12,727

Current income tax (payable to) receivable from Enron Corp. at December 31, 1991, 1990 and 1989 amounted to $(4,522), $(2,310) and $10,467, respectively.

In 1991, the Company utilized a net operating loss carryforward for federal income tax purposes of approximately $32 million that had been included in the Enron Corp. consolidated net operating loss carryforward. The benefits of this net operating loss have been recognized for financial reporting purposes as a reduction of deferred income taxes payable in the period in which they were generated.

In 1991 and 1990, the Company recognized for financial reporting purposes the benefits attributable to the utilization of an approximate $109.5 million previously unrecognized separate company net operating loss carryforward. Of the resulting tax benefits, approximately $7 million and $25 million are reflected in 1991 and 1990 net income, respectively.

7. Commitments and Contingencies

Employee Benefit Plans. Employees of the Company are covered by various retirement, stock purchase and other benefit plans of Enron Corp. During each of the years ended December 31, 1991, 1990 and 1989, the Company was charged $3.6 million, $3.5 million and $1.4 million, respectively, for all such benefits, including pension expense (credit) totaling $.4 million, $.4 million and $(.3) million, respectively, by Enron Corp.

As of September 30, 1991, the most recent valuation date, the actuarial present value of projected plan benefit obligations for the Enron Corp. defined benefit plan in which the employees of the Company participate exceeded the plan net assets by approximately $6.8 million. The assumed discount rate, rate of return on plan assets and rate of increases in wages used in determining the actuarial present value of projected plan benefits were 9.0%, 10.5%, and 5.0%, respectively.

The Company also has in effect a pension and a savings plan related to its Canadian subsidiary. Activity related to these plans is not significant to the Company's operations.

During December 1990, the Financial Accounting Standards Board issued SFAS No. 106 "Accounting for Postretirement Benefits Other Than Pensions" (the "Standard"). The Standard is effective for fiscal years beginning after December 15, 1992 and requires that employers providing health, life insurance and other postretirement benefits (other than pension benefits) accrue the cost of those benefits over the service lives of the employees expected to be eligible to receive such benefits. Such costs are currently recognized on a pay-as-you-go basis. The liability for such benefits existing as of the date of adoption of the Standard (the transition obligation) may be immediately charged to earnings or may be amortized over a period not to exceed 20 years. The Company anticipates that it will adopt the provisions of the Standard during 1993 but has not determined the

method of adoption. Based upon an evaluation of the Company's current postretirement benefit plans and assuming delayed recognition of the transition obligation (estimated to be approximately $2.9 million at January 1, 1993), beginning in 1993 the estimated annual expense to be accrued under the provisions of the Standard would total approximately $.5 million as compared to approximately the same amount on a pay-as-you-go basis.

Enron Oil & Gas Company Executive Compensation Plan. The Company has adopted an executive compensation plan under which grants of full value share ("FVS") and/or share appreciation right ("SAR") units may be granted to individuals who are key employees and to non-employee directors (the "Plan"). The Plan is administered by the Compensation Committee of the Board of Directors of Enron Oil & Gas Company, which consists of designated non-employee directors who do not participate in the Plan. The Plan provides for the issuance of an aggregate of 3 million SAR units and 750,000 FVS units (subject to adjustment in the event of stock dividends, stock splits, and other contingencies). SAR and FVS units are granted at the fair market value (as defined in the Plan) of Company common stock at the time of grant. Upon exercise of FVS units, the grantee receives cash in an amount equal to the fair market value of common stock at the time of exercise. Upon exercise of SAR units, the grantee receives cash in an amount equal to the excess, if any, of the fair market value of common stock at the time of exercise over the fair market value at time of grant. Grants under the Plan vest in accordance with the vesting schedule outlined in each participant's agreement but in no event will vesting occur in less than one year. In the event of dissolution of the Company or certain mergers, consolidations, sales of assets, changes in stock ownership or changes in members of the Company's board of directors, which events are not approved, recommended or supported by a majority of the board of directors of the Company prior to the occurrence of such events, then all outstanding grants of SAR and FVS units will be surrendered to the Company (whether or not then otherwise exercisable) in exchange for a cash payment by the Company for each such surrendered unit in an amount equal to the per share price offered to stockholders in connection with such events or the fair market value of the common stock, less, in the discretion of the Company, the grant price per surrendered unit. Dividends accrue on FVS units only. However, no FVS units were outstanding at December 31, 1991. The following table sets forth SAR transactions for the years ended December 31:

	Number of Shares		
	1991	1990	1989
Outstanding at January 1	1,538,750	1,410,000	-
Granted	193,000	140,500	1,410,000
Exercised (Grant Price of $11.00 per Share)	(114,125)	(9,750)	-
Cancelled	(25,000)	(2,000)	-
Outstanding at December 31	1,592,625	1,538,750	1,410,000
Exercisable at December 31 (Grant Prices of $11.00, $21.50 and $22.625 per Share)	723,500	507,750	220,000

In December 1991, the Board of Directors of the Company adopted the Enron Oil & Gas Company 1992 Stock Plan (the "Stock Plan"). Subsequent to year end, all outstanding SAR units are being cancelled and replaced with options under the Stock Plan, contingent upon stockholder approval of the Stock Plan. Such cancellations and issuances may result in adjustment of previously accrued obligations.

Other Current Liabilities at December 31, 1991 and 1990 includes approximately $5.8 million and $8.0 million, respectively, of accrued obligations relating to exercisable SAR units.

In connection with an employment agreement, as amended, between the Company and the Chairman of the Board, President and Chief Executive Officer of the Company, the Chairman of the Board, President and Chief Executive Officer received from the Company during 1989, a one-time cash payment of $2,250,000, a one-time grant of 400,000 shares of common stock of the Company valued at $11.00 per share at time of grant, and a grant of 1,100,000 SAR units under the Company's Executive Compensation Plan.

Contingencies. There are various suits and claims against the Company having arisen in the ordinary course of business. However, management does not believe these suits and claims will individually or in the aggregate have a material adverse effect on the Company's financial condition or results of operations. The Company has been named as a potentially responsible party in certain Comprehensive Environmental Response Compensation and Liability Act proceedings. However, management does not believe that any potential assessments resulting from such proceedings will individually or in the aggregate have a material adverse effect on the financial condition or results of operations of the Company.

8. Cash Flow Information

In connection with determining Net Operating Cash Inflows, significant gains on sales of certain oil and gas properties in the amount of $14,983,000, $31,802,000 and $12,656,000 are required to be classified as investing cash flows for the years ended December 31, 1991, 1990 and 1989, respectively. However, current accounting guidelines will not permit the relevant federal income tax impact of these transactions to be similarly classified. The current federal income tax impact of these sales transactions was calculated by the Company to be $5,124,000, $15,165,000 and $6,775,000 for the years ended December 31, 1991, 1990 and 1989, respectively, which entered into the overall calculation of current federal income tax. The Company believes that this federal income tax impact should be considered in analyzing the elements of the cash flow statement.

Cash paid for interest and paid (received) for income taxes was as follows for the years ended December 31:

	1991	1990	1989
Interest (net of amount capitalized)	$ 35,449	$ 42,817	$ 28,221
Income taxes	6,618	(8,293)	(15,897)

9. Business Segment Information

The Company's operations are all natural gas and crude oil exploration and production related. Accordingly, such operations are classified as one business segment. Financial information by geographic area is presented below for the years ended December 31, or at December 31:

	1991	1990	1989
Gross Operating Revenues			
United States	$ 436,856	$ 400,218	$ 302,094
Foreign	33,186	33,720	30,906
Total	$ 470,042 (1)	$ 433,938 (1)	$ 333,000 (1)
Operating Income (Loss)			
United States	$ 77,333	$ 46,930	$ 10,373
Foreign	(13,932)	(5,086)	(4,074)
Total	$ 63,401	$ 41,844	$ 6,299
Identifiable Assets			
United States	$1,309,967	$1,276,955	$1,237,831
Foreign	145,641	140,984	127,988
Total	$1,455,608	$1,417,939	$1,365,819

(1) Not deducted are natural gas, crude oil and condensate purchase costs of $82,437, $62,603 and $43,584 in 1991, 1990 and 1989, respectively.

10. Other Income

Other income consists of the following for the years ended December 31:

	1991	1990	1989
Gains on Sales of Oil and Gas Properties	$14,983	$31,802	$12,656
Settlement/Reformation of Natural Gas Sales and Other Contracts	-	-	6,401
Litigation Reserves	(1,200)	(1,200)	(1,750)
Other, Net	(2,439)	(1,649)	134
Total	$11,344	$28,953	$17,441

11. Concentrations of Credit Risk and Other Financial Instruments

Substantially all of the Company's accounts receivable at December 31, 1991 result from crude oil and natural gas sales and/or joint interest billings to affiliate and third party companies in the oil and gas industry. This concentration of customers and joint interest owners may impact the Company's overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions. In determining whether or not to require collateral from a customer or joint interest owner, the Company analyzes the entity's net worth, cash flows, earnings, and credit ratings. Receivables are generally not collateralized. Historical credit losses incurred on receivables by the Company have not been significant.

During 1990 and 1991, the Company entered into certain price swap agreements to, in effect, hedge the market risk caused by fluctuations in the price of natural gas. The agreements call for the Company to make payments to (or receive payments from) the other party based upon the differential between a fixed and a variable price for natural gas as specified by the contract. The current swap agreements run for periods of ten years and have a notional contract amount of approximately $705 million at December 31, 1991.

Interest rate swap agreements in effect at year-end 1991 run for periods of approximately two to four years and have a notional contract amount of approximately $50 million at December 31, 1991. In December 1991 and January 1992 and effective in January 1992, the Company entered into additional interest rate swap agreements with notional amounts totaling $225 million fixing interest rate obligations for one to two years.

While notional contract amounts are used to express the magnitude of price and interest rate swap agreements, the amounts potentially subject to credit risk, in the event of nonperformance by the third parties, are substantially smaller. The Company does not anticipate nonperformance by the third parties.

ENRON OIL & GAS COMPANY

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS

(In Thousands Except Per Share Amounts Unless Otherwise Indicated)
(Unaudited Except for Results of Operations for Oil and Gas Producing Activities)

Oil and Gas Producing Activities

The following disclosures are made in accordance with SFAS No. 69 – "Disclosures about Oil and Gas Producing Activities":

Oil and Gas Reserves. Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" crude oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved reserves represent estimated quantities of crude oil, condensate, natural gas and natural gas liquids that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made.

Proved developed reserves are proved reserves expected to be recovered, through wells and equipment in place and under operating methods being utilized at the time the estimates were made.

Canadian provincial royalties are determined based on a graduated percentage scale which varies with prices and production volumes. Canadian reserves, as presented on a net basis, assume prices and royalty rates in existence at the time the estimates were made, and the Company's estimate of future production volumes. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause the Company's share of future production from Canadian reserves to be materially different from that presented.

Estimates of proved and proved developed reserves at December 31, 1989, 1990 and 1991 were based on studies performed by the Company's engineering staff for reserves in both the United States and Canada. Opinions by DeGolyer and MacNaughton, independent petroleum consultants, for the years ended December 31, 1989, 1990 and 1991 covering producing areas containing 75%, 72% and 73%, respectively, of proved reserves of the Company on a net-equivalent-cubic-feet-of-gas basis, indicate that the estimates of proved reserves prepared by the Company's engineering staff for the properties reviewed by DeGolyer and MacNaughton, when compared in total on a net-equivalent-cubic-feet-of-gas basis, do not differ materially from the estimates prepared by DeGolyer and MacNaughton. Such estimates by DeGolyer and MacNaughton in the aggregate varied by not more than 5% from those prepared by the Company's engineering staff. All reports by DeGolyer and MacNaughton were developed utilizing geological and engineering data provided by the Company.

No major discovery or other favorable or adverse event subsequent to December 31, 1991 is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

The following table sets forth the Company's net proved and proved developed reserves at December 31 for each of the four years in the period ended December 31, 1991, and the changes in the net proved reserves for each of the three years in the period then ended as estimated by the Company's engineering staff.

NET PROVED AND PROVED DEVELOPED RESERVE SUMMARY

	United States	Canada	Total
Natural Gas (MMcf)			
Proved reserves at December 31, 1988	1,199,180	83,573	1,282,753
Revisions of previous estimates	5,574	(747)	4,827
Purchases in place	33,927	289	34,216
Extensions, discoveries and other additions	223,896	27,046	250,942
Sales in place	(27,680)	–	(27,680)
Production	(123,319)	(6,145)	(129,464)
Proved reserves at December 31, 1989	1,311,578	104,016	1,415,594
Revisions of previous estimates	(35,851)	(108)	(35,959)
Purchases in place	73,981	3,729	77,710
Extensions, discoveries and other additions	184,225	30,534	214,759
Sales in place	(25,988)	(64)	(26,052)
Production	(164,478)	(6,599)	(171,077)
Proved reserves at December 31, 1990	1,343,467	131,508	1,474,975
Revisions of previous estimates	48,371	35	48,406
Purchases in place	45,030	2,885	47,915
Extensions, discoveries and other additions	199,410	6,193	205,603
Sales in place	(6,933)	(2,477)	(9,410)
Production	(173,460)	(9,237)	(182,697)
Proved reserves at December 31, 1991	1,455,885	128,907	1,584,792
Liquids (MBbl)(1)			
Proved reserves at December 31, 1988	23,896	6,230	30,126
Revisions of previous estimates	(513)	317	(196)
Purchases in place	300	53	353
Extensions, discoveries and other additions	1,091	858	1,949
Sales in place	(4,875)	(4)	(4,879)
Production	(2,247)	(943)	(3,190)
Proved reserves at December 31, 1989	17,652	6,511	24,163
Revisions of previous estimates	1,615	424	2,039
Purchases in place	1,495	115	1,610
Extensions, discoveries and other additions	1,238	1,257	2,495
Sales in place	(3,473)	(574)	(4,047)
Production	(2,255)	(877)	(3,132)
Proved reserves at December 31, 1990	16,272	6,856	23,128
Revisions of previous estimates	(86)	256	170
Purchases in place	173	42	215
Extensions, discoveries and other additions	983	310	1,293
Sales in place	(1,248)	(25)	(1,273)
Production	(2,272)	(927)	(3,199)
Proved reserves at December 31 1991	13,822	6,512	20,334

(Table continued on following page)

	United States	Canada	Total
Proved developed reserves at			
Natural Gas (MMcf)			
December 31, 1988	849,820	68,854	918,674
December 31, 1989	942,118	91,840	1,033,958
December 31, 1990	1,023,711	114,045	1,137,756
December 31, 1991	1,138,530	112,975	1,251,505
Liquids (MBbl)(1)			
December 31, 1988	20,573	6,090	26,663
December 31, 1989	15,743	6,459	22,202
December 31, 1990	15,269	6,804	22,073
December 31, 1991	13,002	6,484	19,486

(1) Includes crude oil, condensate and natural gas liquids.

Capitalized Costs Relating to Oil and Gas Producing Activities. The following table sets forth the capitalized costs relating to the Company's natural gas and crude oil producing activities at December 31, 1991 and 1990:

	1991	1990
Proved properties	$2,162,013	$1,997,176
Unproved properties	66,621	68,823
Total	2,228,634	2,065,999
Accumulated depreciation, depletion and amortization	(888,968)	(760,863)
Net capitalized costs	$1,339,666	$1,305,136

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities. The acquisition, exploration and development costs disclosed in the following tables are in accordance with definitions in SFAS No. 19 – "Financial Accounting and Reporting by Oil and Gas Producing Companies".

Acquisition costs include costs incurred to purchase, lease, or otherwise acquire property.

Exploration costs include exploration expenses, additions to exploration wells in progress, and depreciation of support equipment used in exploration activities.

Development costs include additions to production facilities and equipment, additions to development wells in progress and related facilities, and depreciation of support equipment and related facilities used in development activities.

The following tables set forth costs incurred related to the Company's oil and gas activities for the years ended December 31:

	United States	Foreign		Total
		Canada	Other	
1991				
Acquisition Costs of Properties				
Unproved	$ 12,156	$ 223	$ 176	$ 12,555
Proved	40,039	2,362	–	42,401
Total	52,195	2,585	176	54,956
Exploration Costs	39,916	5,369	15,062	60,347
Development Costs	132,200	10,338	–	142,538
Total	$224,311	$18,292	$15,238	$257,841

(Table continued on following page)

	United States	Foreign		Total
		Canada	Other	
1990				
Acquisition Costs of Properties				
Unproved	$ 47,152	$ 2,099	$ 351	$ 49,602
Proved	59,119	788	–	59,907
Total	106,271	2,887	351	109,509
Exploration Costs	53,633	9,644	9,842	73,119
Development Costs	105,834	20,152	263	126,249
Total	$265,738	$32,683	$10,456	$308,877
1989				
Acquisition Costs of Properties				
Unproved	$ 27,031	$ 3,833	$ 250	$ 31,114
Proved	31,016	191	–	31,207
Total	58,047	4,024	250	62,321
Exploration Costs	34,717	9,548	6,691	50,956
Development Costs	110,946	9,331	–	120,277
Total	$203,710	$22,903	$ 6,941	$233,554

Results of Operations for Oil and Gas Producing Activities(1). The following tables set forth results of operations for oil and gas producing activities for the years ended December 31:

	United States	Foreign		Total
		Canada	Other	
1991				
Operating Revenues				
Associated Companies	$197,841	$10,244	$ –	$208,085
Trade	78,964	19,004	–	97,968
Total	276,805	29,248	–	306,053
Exploration Expenses, including Dry Hole	28,107	3,659	14,402	46,168
Production Costs	56,167	9,418	–	65,585
Impairment of Unproved Oil and Gas Properties	10,342	2,449	–	12,791
Depreciation, Depletion and Amortization	148,401	12,385	99	160,885
Income (Loss) before Income Taxes	33,788	1,337	(14,501)	20,624
Income Tax Provision (Benefit)	(12,094)	455	(4,930)	(16,569)
Results of Operations	$ 45,882	$ 882	$ (9,571)	$ 37,193
1990				
Operating Revenues				
Associated Companies	$179,521	$11,293	$ –	$190,814
Trade	109,538	18,123	–	127,661
Total	289,059	29,416	–	318,475
Exploration Expenses, including Dry Hole	33,086	5,089	9,842	48,017
Production Costs	57,520	7,168	–	64,688
Impairment of Unproved Oil and Gas Properties	18,653	1,918	–	20,571
Depreciation, Depletion and Amortization	145,647	10,169	61	155,877
Income (Loss) before Income Taxes	34,153	5,072	(9,903)	29,322
Income Tax Provision (Benefit)	(8,926)	1,724	(3,367)	(10,569)
Results of Operations	$ 43,079	$ 3,348	$ (6,536)	$ 39,891

(Table continued on following page)

1989	United States	Foreign Canada	Foreign Other	Total
Operating Revenues				
Associated Companies	$134,033	$ 7,993	$ -	$142,026
Trade	97,770	18,347	-	116,117
Total	231,803	26,340	-	258,143
Exploration Expenses, including Dry Hole	22,708	4,763	6,729	34,200
Production Costs	54,034	7,174	-	61,208
Impairment of Unproved Oil and Gas Properties	9,176	1,656	-	10,832
Depreciation, Depletion and Amortization	122,420	11,847	46	134,313
Income (Loss) before Income Taxes	23,465	900	(6,775)	17,590
Income Tax Provision (Benefit)	8,276	306	(2,304)	6,278
Results of Operations	$ 15,189	$ 594	$ (4,471)	$ 11,312

(1) Excludes net revenues associated with other marketing activities, interest charges, general corporate expenses and certain gathering and handling fees for each of the three years in the period ended December 31, 1991. The gathering and handling fees and other marketing net revenues are directly associated with oil and gas operations with regard to segment reporting as defined in SFAS No. 14 – "Financial Reporting for Segments of a Business Enterprise", but are not part of Disclosures about Oil and Gas Producing Activities as defined in SFAS No. 69.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves. The following information has been developed utilizing procedures prescribed by SFAS No. 69 and based on crude oil and natural gas reserve and production volumes estimated by the engineering staff of the Company. It may be useful for certain comparison purposes, but should not be solely relied upon in evaluating the Company or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of the Company.

The future cash flows presented below are based on sales prices, cost rates, and statutory income tax rates in existence as of the date of the projections. It is expected that material revisions to some estimates of crude oil and natural gas reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The following table sets forth the standardized measure of discounted future net cash flows from projected production of the Company's crude oil and natural gas reserves at December 31, for the years ended December 31:

	United States	Canada	Total
1991			
Future revenues(1)	$2,501,439	$269,917	$2,771,356
Future production costs	(504,420)	(79,413)	(583,833)
Future development costs	(189,091)	(6,132)	(195,223)
Future net cash flows before income taxes	1,807,928	184,372	1,992,300
Discount to present value at 10% annual rate	(618,919)	(62,137)	(681,056)
Present value of future net cash flows before income taxes	1,189,009	122,235	1,311,244
Future income taxes discounted at 10% annual rate(2)	(127,188)	(27,979)	(155,167)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves(1)	$1,061,821	$ 94,256	$1,156,077
1990			
Future revenues(1)	$2,550,360	$349,811	$2,900,171
Future production costs	(525,907)	(74,236)	(600,143)
Future development costs	(180,508)	(7,515)	(188,023)
Future net cash flows before income taxes	1,843,945	268,060	2,112,005
Discount to present value at 10% annual rate	(678,352)	(89,827)	(768,179)
Present value of future net cash flows before income taxes	1,165,593	178,233	1,343,826
Future income taxes discounted at 10% annual rate(2)	(237,009)	(47,491)	(284,500)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves(1)	$ 928,584	$130,742	$1,059,326
1989			
Future revenues(1)	$2,769,296	$271,426	$3,040,722
Future production costs	(612,391)	(49,106)	(661,497)
Future development costs	(208,715)	(4,338)	(213,053)
Future net cash flows before income taxes	1,948,190	217,982	2,166,172
Discount to present value at 10% annual rate	(767,342)	(78,888)	(846,230)
Present value of future net cash flows before income taxes	1,180,848	139,094	1,319,942
Future income taxes discounted at 10% annual rate(2)	(292,261)	(32,428)	(324,689)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves(1)	$ 888,587	$106,666	$ 995,253

(1) Based on year-end market prices determined at the point of delivery from the producing unit.

(2) Future income taxes before discount were $279.4 million U.S., $53.0 million Canada and $332.4 million total; $455.1 million U.S., $80.6 million Canada and $535.7 million total; and $559.7 million U.S., $61.1 million Canada and $620.8 million total for the years ended December 31, 1991, 1990 and 1989, respectively.

Changes in Standardized Measure of Discounted Future Net Cash Flows. The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31, for each of the three years in the period ended December 31, 1991.

	United States	Canada	Total
December 31, 1988	$ 759,539	$ 84,647	$ 844,186
Sales and transfers of oil and gas produced, net of production costs	(177,769)	(19,166)	(196,935)
Net changes in prices and production costs	93,203	13,220	106,423
Extensions, discoveries, additions and improved recovery net of related costs	230,925	29,354	260,279
Development costs incurred	28,849	–	28,849
Revisions of estimated development costs	1,798	256	2,054
Revisions of previous quantity estimates	2,185	1,170	3,355
Accretion of discount	95,585	10,740	106,325
Net change in income taxes	(95,953)	(9,672)	(105,625)
Purchases of reserves in place	23,951	555	24,506
Sales of reserves in place	(50,983)	(58)	(51,041)
Changes in timing and other	(22,743)	(4,380)	(27,123)
December 31, 1989	888,587	106,666	995,253
Sales and transfers of oil and gas produced, net of production costs	(231,539)	(22,248)	(253,787)
Net changes in prices and production costs	(117,213)	7,412	(109,801)
Extensions, discoveries, additions and improved recovery net of related costs	179,831	38,483	218,314
Development costs incurred	62,194	535	62,729
Revisions of estimated development costs	8,397	183	8,580
Revisions of previous quantity estimates	(21,481)	2,484	(18,997)
Accretion of discount	118,085	13,910	131,995
Net change in income taxes	55,252	(15,063)	40,189
Purchases of reserves in place	84,874	3,801	88,675
Sales of reserves in place	(97,910)	(4,996)	(102,906)
Changes in timing and other	(493)	(425)	(918)
December 31, 1990	928,584	130,742	1,059,326
Sales and transfers of oil and gas produced, net of production costs	(220,638)	(19,830)	(240,468)
Net changes in prices and production costs	(150,061)	(51,609)	(201,670)
Extensions, discoveries, additions and improved recovery net of related costs	212,097	4,802	216,899
Development costs incurred	36,719	11	36,730
Revisions of estimated development costs	1,640	2,833	4,473
Revisions of previous quantity estimates	37,535	1,178	38,713
Accretion of discount	116,559	17,823	134,382
Net change in income taxes	109,821	19,512	129,333
Purchases of reserves in place	38,350	(558)	37,792
Sales of reserves in place	(17,321)	(2,328)	(19,649)
Changes in timing and other	(31,464)	(8,320)	(39,784)
December 31, 1991	$1,061,821	$ 94,256	$1,156,077

Unaudited Quarterly Financial Information

	Quarter Ended			
	March 31	June 30	Sept. 30	Dec. 31
1991				
Net Operating Revenues	$95,894	$ 87,971	$83,956	$119,784
Operating Income	$19,139	$ 12,899	$ 6,050	$ 25,313
Income before Income Taxes	$11,182	$ 3,562	$11,265	$ 19,660
Income Tax Benefit	(705)	(3,690)	(2,162)	(2,708)
Net Income	$11,887	$ 7,252	$13,427	$ 22,368
Earnings Per Share of Common Stock	$ .16	$ .10	$ .18	$ .29
Average Number of Common Shares	75,900	75,900	75,900	75,900
1990				
Net Operating Revenues	$96,260	$ 78,585	$78,454	$118,036
Operating Income (Loss)	$21,524	$ 3,406	$ (6,712)	$ 23,626
Income before Income Taxes	$12,300	$ 5,986	$ 3,058	$ 13,270
Income Tax Provision (Benefit)	1,077	391	(5,417)	(6,905)
Net Income	$11,223	$ 5,595	$ 8,475	$ 20,175
Earnings Per Share of Common Stock	$ .15	$ .07	$ .11	$ .27
Average Number of Common Shares	75,900	75,900	75,900	75,900
1989				
Net Operating Revenues	$74,568	$ 65,247	$64,443	$ 85,158
Operating Income (Loss)	$ 6,247	$ (14,183)	$ 1,411	$ 12,824
Income (Loss) before Income Taxes	$ (1,233)	$ (6,302)	$ (5,113)	$ 3,163
Income Tax Provision (Benefit)	(515)	(2,173)	(1,796)	1,100
Net Income (Loss)	$ (718)	$ (4,129)	$ (3,317)	$ 2,063
Earnings (Loss) Per Share of Common Stock	$ (.01)	$ (.06)	$ (.05)	$ .03
Average Number of Common Shares	64,000	64,000	64,300	73,025

ENRON OIL & GAS COMPANY

SCHEDULE V — PROPERTY, PLANT AND EQUIPMENT

For the Years Ended December 31, 1991, 1990 and 1989
(In Thousands)

Column A	Column B	Column C	Column D	Column E	Column F
Classification	Balance at Beginning of Year	Additions At Cost	Retirements	Other Changes Add (Deduct)(a)	Balance at End of Year
1991					
Oil and Gas Properties	$2,065,999	$211,673	$ 38,339	$(10,699)	$2,228,634
1990					
Oil and Gas Properties	$1,893,357	$260,860	$ 70,945	$(17,273)	$2,065,999
1989					
Oil and Gas Properties	$1,794,494	$199,354	$ 97,063	$ (3,428)	$1,893,357

(a) Includes, among other things, amortized impairments of unproved oil and gas properties and foreign currency translation adjustments.

ENRON OIL & GAS COMPANY

SCHEDULE VI—ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT
For the Years Ended December 31, 1991, 1990 and 1989
(In Thousands)

Column A	Column B	Column C	Column D	Column E	Column F
Classification	Balance at Beginning of Year	Additions Charged to Costs and Expenses	Retirements	Other Changes Add (Deduct)	Balance at End of Year
1991					
Oil and Gas Properties	$760,863	$160,885	$ 30,802	$ (1,978)	$888,968
1990					
Oil and Gas Properties	$643,700	$155,877	$ 36,204	$ (2,510)	$760,863
1989					
Oil and Gas Properties	$571,726	$134,313	$ 65,939	$ 3,600	$643,700

ENRON OIL & GAS COMPANY

SCHEDULE VIII — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
For the Years Ended December 31, 1991, 1990 and 1989
(In Thousands)

Column A	Column B	Column C	Column D	Column E
Description	Balance at Beginning of Year	Additions Charged to Costs and Expenses	Deductions For Purpose For Which Reserves Were Created	Balance at End of Year
1991				
Reserves deducted from assets to which they apply –				
Revaluation of Accounts Receivable	$ 4,796	$ 2,600	$ 1,740	$ 5,656
Litigation Reserve(a)	$ 1,400	$ 1,200	$ 1,518	$ 1,082
1990				
Reserves deducted from assets to which they apply –				
Revaluation of Accounts Receivable	$ 4,772	$ 600	$ 576	$ 4,796
Revaluation of Inventories	$ 204	$ –	$ 204	$ –
Litigation Reserve(a)	$ 1,725	$ 1,200	$ 1,525	$ 1,400
1989				
Reserves deducted from assets to which they apply –				
Revaluation of Accounts Receivable	$ 4,692	$ 200	$ 120	$ 4,772
Revaluation of Inventories	$ 366	–	$ 162	$ 204
Litigation Reserve(a)	$ 8,000	$ 1,750	$ 8,025	$ 1,725
Property Sale Loss Reserve(a)	$15,000	–	$15,000	–

(a) Included in Other Liabilities on the consolidated balance sheets.

ENRON OIL & GAS COMPANY

SCHEDULE X — SUPPLEMENTAL INCOME STATEMENT INFORMATION

For the Years Ended December 31, 1991, 1990 and 1989
(In Thousands)

Column A	Column B		
	Charged to Costs and Expenses		
Item	1991	1990	1989
Maintenance and repairs	$ 7,107	$ 7,429	$ 4,159
Taxes, other than payroll and income taxes			
Property	$ 6,401	$ 6,866	$ 6,994
Production/Severance	9,262	14,016	14,496
Windfall Profits	-	-	(175)
Franchise	575	297	871
Other	124	95	(20)
Total	$16,362	$21,274	$22,166

EXHIBITS

Exhibits not incorporated herein by reference to a prior filing are designated by an asterisk (*) and are filed herewith; all exhibits not so designated are incorporated herein by reference to the Company's Form S-1 Registration Statement, Registration No. 33-30678, filed on August 24, 1989 ("Form S-1"), or as otherwise indicated.

3.1 –Restated Certificate of Incorporation of Enron Oil & Gas Company (Exhibit 3.1 to Form S-1).

3.2 –Bylaws of Enron Oil & Gas Company (Exhibit 3.2 to the Company's Annual Report on Form 10-K for the year ended December 31, 1990).

3.3 –Specimen of Certificate evidencing the Common Stock (Exhibit 3.3 to Form S-1).

4.1* –Promissory Note due May 1, 1996, dated May 1, 1991.

4.2 –There have not been filed as exhibits to this Form 10-K debt instruments defining the rights of holders of long-term debt of the Company, none of which relates to authorized indebtedness that exceeds 10% of the consolidated assets of the Company and its subsidiaries. The Company hereby agrees to furnish a copy of any such instrument to the Commission upon request.

10.1 –Services Agreement, dated as of January 1, 1989, between Enron Oil & Gas Company and Enron Corp. (Exhibit 10.1 to Form S-1).

10.2 –Stock Restriction and Registration Agreement dated as of August 23, 1989 (Exhibit 10.2 to Form S-1).

10.3 –Tax Allocation Agreement dated as of August 23, 1989 (Exhibit 10.3 to Form S-1).

10.4 –Enron Corp. Deferral Plan dated December 10, 1985 (Exhibit 10.12 to Form S-1).

10.5 –Enron Corp. 1988 Stock Plan (Exhibit 10.13 to Form S-1).

10.6 –Enron Oil & Gas Company Key Contributor Incentive Plan (Exhibit 10.6 to the Company's Annual Report on Form 10-K for the year ended December 31, 1990).

10.7 –Enron Corp. 1984 Stock Option Plan (Exhibit 10.15 to Form S-1).

10.8 –Enron Corp. 1986 Stock Option Plan (Exhibit 10.16 to Form S-1).

10.9 –Enron Corp. Restricted Stock Plan dated April 10, 1986 (Exhibit 10.17 to Form S-1).

10.10 –Employment Agreement between Enron Oil & Gas Company and Forrest Hoglund, dated as of September 1, 1987, as amended (Exhibit 10.19 to Form S-1).

10.11 –Enron Oil & Gas Company Executive Compensation Plan (Exhibit 10.20 to Form S-1).

10.12 –Fuel Supply Contract, dated as of June 30, 1986, as amended, by and between Enron Oil & Gas Company, HNG Oil Company, BelNorth Petroleum Corporation and Enron Cogenration One Company, as amended (Exhibit 10.23 to Form S-1).

10.13 –Gas Sales Contract dated September 2, 1987 between Enron Oil & Gas Company and Cogenron Inc., as amended (Exhibit 10.24 to Form S-1).

10.14 –Letter Agreement dated August 20, 1987 between Enron Oil & Gas Company and Panhandle Gas Company (Exhibit 10.25 to Form S-1).

10.15 –Pension Program for Enron Corp. Deferral Plan Participants, effective January 1, 1985, as amended (Exhibit 10.29 to Form S-1).

10.16 –Credit Agreement, dated as of December 4, 1990, among Enron Oil & Gas Company, the Banks named therein and CitiBank, N.A., as Agent (Exhibit 10.16 to the Company's Annual Report on Form 10-K for the year ended December 31, 1990).

10.17*	–Interest Rate and Currency Exchange Agreement, dated as of June 1, 1991, between Enron Risk Management Services Corp. and Enron Oil & Gas Marketing, Inc.
10.18	–Letter Agreement between Colorado Interstate Gas Company and Enron Oil & Gas Marketing, Inc. dated November 1, 1990 (Exhibit 10.18 to the Company's Annual Report on Form 10-K for the year ended December 31, 1990).
10.19	–Gathering Agreement between Enron Oil & Gas Company and Northwest Pipeline Corporation dated March 30, 1989, as amended (Exhibit 10.36 to Form S-1).
10.20	–Processing Agreement between Enron Oil & Gas Company and Northwest Pipeline Corporation dated March 30, 1989 (Exhibit 10.37 to Form S-1).
10.21	–Gas Sales Agreement between Enron Gas Marketing, Inc. and Enron Oil & Gas Marketing, Inc. dated August 22, 1989 (Exhibit 10.38 to Form S-1).
10.22	–Gas Purchase Agreement between Enron Gas Marketing, Inc. and Enron Oil & Gas Marketing, Inc. dated August 22, 1989 (Exhibit 10.39 to Form S-1).
10.23	–Gas Purchase Agreement between Enron Gas Marketing, Inc. and Enron Oil & Gas Marketing, Inc. dated August 22, 1989 (Exhibit 10.40 to Form S-1).
10.24	–Gas Purchase Agreement between Enron Oil & Gas Company and Enron Oil & Gas Marketing, Inc. dated August 22, 1989 (Exhibit 10.41 to Form S-1).
10.25	–Gas Purchase Agreement between Enron Oil & Gas Company and Enron Oil & Gas Marketing, Inc. dated August 22, 1989 (Exhibit 10.42 to Form S-1).
10.26	–Seasonal Gas Purchase Contract dated July 21, 1989 between Enron Oil & Gas Marketing, Inc. and Northern Natural Gas Company (Exhibit 10.43 to Form S-1).
10.27	–Enron Corp. 1988 Deferral Plan (Exhibit 10.49 to Form S-1).
10.28	–Form of Enron Corp. Long-Term Incentive Plan Effective as of January 1, 1987 (Exhibit 10.50 to Form S-1).
10.29	–Enron Executive Supplemental Survivor Benefits Plan Effective January 1, 1987 (Exhibit 10.51 to Form S-1).
10.30	–1988 FlexPerq Program Summary (Exhibit 10.52 to Form S-1).
10.31	–Enron Corp. 1988 Key Employee Annual Incentive Plan (Exhibit 10.55 to Form S-1).
10.32	–Enron Corp. 1988 Executive Annual Incentive Plan (Exhibit 10.56 to Form S-1).
10.33	–Gas Purchase Agreement between Enron Oil & Gas Company and Enron Gas Marketing, Inc. dated October 30, 1990 (Exhibit 10.33 to the Company's Annual Report on Form 10-K for the year ended December 31, 1990).
10.34	–Credit Agreement between Enron Corp. and Enron Oil & Gas Company dated October 12, 1989 (Exhibit 10.34 to the Company's Annual Report on Form 10-K for the year ended December 31, 1990).
10.35	–Credit Agreement between Enron Oil & Gas Company and Enron Corp. dated October 12, 1989 (Exhibit 10.35 to the Company's Annual Report on Form 10-K for the year ended December 31, 1990).
10.36	–First Amendment to Gas Sales Agreement between Enron Gas Marketing, Inc. and Enron Oil & Gas Company, dated as of November 1, 1990 (Exhibit 10.36 to the Company's Annual Report on Form 10-K for the year ended December 31, 1990).
10.37	–Swap Agreement between Banque Paribas and Enron Oil & Gas Company, dated as of December 5, 1990 (Exhibit 10.37 to the Company's Annual Report on Form 10-K for the year ended December 31, 1990).
10.38*	–Interest Rate and Currency Exchange Agreement dated as of March 25, 1991, between Enron Oil & Gas Marketing, Inc. and Enron Finance Corp.

10.39*	–Warranty Gas Purchase Contract between Enron Gas Marketing, Inc. and Enron Oil & Gas Marketing, Inc. dated March 25, 1991, as amended.
10.40*	–Enron Oil & Gas Company 1992 Stock Plan.
10.41*	–Enron Corp. 1992 Deferral Plan.
22*	–List of subsidiaries.
24.1*	–Consent of DeGolyer and MacNaughton.
24.2*	–Opinion of DeGolyer and MacNaughton dated January 23, 1992.
25*	–Powers of Attorney.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 20th day of March, 1992.

ENRON OIL & GAS COMPANY
(Registrant)

By /s/ WALTER C. WILSON
(Walter C. Wilson)
Senior Vice President and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of registrant and in the capacities with Enron Oil & Gas Company indicated and on the 20th day of March, 1992.

Signature	Title
/s/ FORREST E. HOGLUND **(Forrest E. Hoglund)**	Chairman of the Board, President and Chief Executive Officer and Director (Principal Executive Officer)
/s/ WALTER C. WILSON **(Walter C. Wilson)**	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ BEN B. BOYD **(Ben B. Boyd)**	Vice President and Controller (Principal Accounting Officer)
FRED C. ACKMAN * **(Fred C. Ackman)**	Director
RICHARD D. KINDER * **(Richard D. Kinder)**	Director
KENNETH L. LAY * **(Kenneth L. Lay)**	Director
EDWARD RANDALL, III * **(Edward Randall, III)**	Director

* /s/ PEGGY B. MENCHACA
(Peggy B. Menchaca)
(Attorney-in-fact for persons indicated)

FORM 3160-5
(December 1989)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
Budget Bureau No. 1004-0135
Expires September 30, 1990

SUNDRY NOTICE AND REPORTS ON WELLS

Do not use this form for proposals to drill or to deepen or reentry to a different reservoir.
Use "APPLICATION FOR PERMIT --" for such proposals
SUBMIT IN TRIPLICATE

5. Lease Designation and Serial No.
U 0144869

6. If Indian, Allottee or Tribe Name

7. If Unit or C.A., Agreement Designation
NATURAL BUTTES UNIT

1. Type of Well
[ ] Oil Well [X] Gas Well [ ] Other

8. Well Name and No.
NATURAL BUTTES UNIT ~~20-21B~~ 21-20B

2. Name of Operator
ENRON OIL & GAS COMPANY

3. Address and Telephone No.
P.O. BOX 250, BIG PINEY, WY 83113 (307) 276-3331

9. API Well No.
43-047-30359

4. Location of Well (Footage, Sec., T., R., M., or Survey Description)
1037' FNL - 1033' FEL (NE/NE)
SECTION 20, T9S, R20E

10. Field and Pool or Exploratory Area
NATURAL BUTTES/WASATCH

11. County or Parrish, State
UINTAH WYOMING

12. CHECK APPROPRIATE BOX(s) TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION	
[X] NOTICE OF INTENT	[ ] ABANDONMENT	[ ] CHANGE OF PLANS
	[ ] RECOMPLETION	[ ] NEW CONSTRUCTION
[ ] SUBSEQUENT REPORT	[ ] PLUGGING BACK	[ ] NON-ROUTINE FRACTURING
	[ ] CASING REPAIR	[ ] WATER SHUT-OFF
[ ] FINAL ABANDONMENT NOTICE	[ ] ALTERING CASING	[ ] CONVERSION TO INJECTION
	[X] OTHER TEST FOR WATER DISPOSAL POTENTIAL	

(Note: Report results of multiple completion on Well Completions or Recompletion Report and Log Form.)

13. Describe Proposed or Completed Operations (Clearly state all pertinent details and give pertinent dates, including estimated date of starting any proposed work if well is directionally drilled give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work).

Enron Oil & Gas Company proposes to set a CIBP above existing Wasatch perforations in the subject well for the purpose of testing the Green River "H" sand for water disposal potential. The "H" sand will be perforated from 3802-25' w/2 SPF and the formation water analyzed for total dissolved solids. A step rate test will then be obtained to determine formation injectivity data. If the sand appears to be an acceptable candidate for disposal, Enron will then proceed with the necessary permitting to allow final conversion of the well to disposal status.

Accepted by the State of Utah Division of Oil, Gas and Mining
Date: 2-3-92
By: [signature]

RECEIVED
JAN 27 1992
DIVISION OF
OIL GAS & MINING

14. I hereby certify that the foregoing is true and correct

SIGNED Katy Carlson TITLE *Regulatory Analyst* DATE 1-23-92

(This space for Federal or State office use)

APPROVED BY TITLE DATE

CONDITIONS OF APPROVAL, IF ANY:

Federal Approval of this Action is Necessary

ENRON
Oil & Gas Company
P.O. Box 250 Big Piney, Wyoming 83113 (307) 276-3331

January 23, 1992

Mr. Ed Forsman
Bureau Of Land Management
Vernal District
170 South 500 East
Vernal, Utah 84078

RE: NATURAL BUTTES UNIT 21-20B
LEASE: U 0144869
NENE, SEC. 20, T9S, R20E
UINTAH COUNTY, UTAH

Dear Mr. Forsman:

Please find attached a Sundry Notice describing Enron Oil & Gas Company's proposal to test the subject well for water disposal potential.

If you have any questions or need additional information, please contact this office.

Very truly yours,

ENRON OIL & GAS COMPANY

Darrell E. Zlomke
District Manager

kc

cc: Utah Board of Oil, Gas and Mining
D. Weaver
T. Miller
Vernal Office
File

Form OGC-1b

SUBMIT IN TRIPLICATE*

STATE OF UTAH
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL, GAS, AND MINING

5. LEASE DESIGNATION AND SERIAL NO.
U 0144869

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

SUNDRY NOTICES AND REPORTS ON WELLS

(Do not use this form for proposals to drill or to deepen or plug back to a different reservoir. Use "APPLICATION FOR PERMIT—" for such proposals.)

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME
NATURAL BUTTES UNIT

2. NAME OF OPERATOR
ENRON OIL & GAS COMPANY

8. FARM OR LEASE NAME

3. ADDRESS OF OPERATOR
P. O. BOX 1815 VERNAL, UT 84078

9. WELL NO.
21-20B

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1037' FNL & 1033' FEL NE/NE

10. FIELD AND POOL, OR WILDCAT
NBU WASATCH

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
SEC 20, T9S, R20E

14. PERMIT NO.
43 047 30359

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
4785' KB

12. COUNTY OR PARISH
UINTAH

13. STATE
UTAH

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:

- TEST WATER SHUT-OFF ☐
- FRACTURE TREAT ☐
- SHOOT OR ACIDIZE ☐
- REPAIR WELL ☐
- PULL OR ALTER CASING ☐
- MULTIPLE COMPLETE ☐
- ABANDON* ☐
- CHANGE PLANS ☐
- (Other) ☐

SUBSEQUENT REPORT OF:

- WATER SHUT-OFF ☐
- FRACTURE TREATMENT ☐
- SHOOTING OR ACIDIZING ☐
- REPAIRING WELL ☐
- ALTERING CASING ☐
- ABANDONMENT* ☐
- (Other) ANNUAL STATUS REPORT ☒

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

SI - BEING MADE INTO A SALT WATER DISPOSAL WELL, APPLICATION WILL BE SUBMITTED

FEB 04 1992

18. I hereby certify that the foregoing is true and correct

SIGNED Carol E Hatch TITLE PRODUCTION ANALYST DATE 2-3-92

(This space for Federal or State office use)

APPROVED BY ____ TITLE ____ DATE ____
CONDITIONS OF APPROVAL, IF ANY:

*See Instructions on Reverse Side

ENRON
Oil & Gas Company

P.O. Box 250 Big Piney, Wyoming 83113 (307) 276-3331

RECEIVED
APR 13 1992
DIVISION OF
OIL GAS & MINING

April 10, 1992

Mr. Gustav Stolz, Jr., P.E.
U.S. Environmental Protection Agency
Denver Place
999 18th Street, Suite 500
Denver, Colorado 80202-2405

RE: UNDERGROUND INJECTION CONTROL
PERMIT APPLICATION
NATURAL BUTTES UNIT 21-20B
NE/NE, SEC. 20, T9S, R20E
UINTAH, UTAH
43-047-20359

Dear Mr. Stolz:

Please find enclosed, the Underground Injection Control Permit Application and associated attachments for conversion of the Natural Buttes Unit 21-20B well to water disposal. A copy of the Sundry Notice to the Bureau of Land Management requesting authorization for conversion of the well to water disposal is attached.

If additional information is required, please contact Jim Schaefer of this office.

Very truly yours,

ENRON OIL & GAS COMPANY

C.C. Parsons

C.C. Parsons
District Manager

kc

Attachments

cc: State of Utah - Division of Oil, Gas, & Mining
D. Weaver
J. Tigner - 2043
Vernal Office
File

ENRON

Oil & Gas Company

P.O. Box 250 Big Piney, Wyoming 83113 (307) 276-3331

April 10, 1992

Mr. Ed Forsman
Bureau Of Land Management
Vernal District
170 South 500 East
Vernal, Utah 84078

RE: WATER DISPOSAL PERMIT
NATURAL BUTTES UNIT 21-20B
SECTION 20, T9S, R20E
UINTAH COUNTY, UTAH

Dear Mr. Forsman:

A Sundry Notice submitted on January 23, 1992, requesting authorization for testing of the subject well for water disposal potential, was subsequently approved by your office on February 27th, 1992. Injection tests indicated that the well will be a suitable candidate for disposal of produced water, therefore Enron Oil & Gas Company has submitted the necessary Underground Injection Control Permit Application forms to the Environmental Protection Agency for review and approval. A copy has also been submitted to the State of Utah, Division of Oil, Gas, and Mining.

Please find attached a Sundry Notice requesting Bureau of Land Management authorization for conversion of the subject well from shut-in gas well to water disposal well. Also find attached a copy of the Underground Injection Control Permit Application which has been submitted to the EPA.

If you have any questions or require additional information, please contact Jim Schaefer of this office.

Very truly yours

ENRON OIL & GAS COMPANY

C.C. Parsons

C.C. Parsons
District Manager

JRS/kc
cc: D. Weaver
T. Miller
Vernal Office
J. Tignar-2043
File

FORM 3160-5
December 1989)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
Budget Bureau No. 1004-0135
Expires September 30, 1990

SUNDRY NOTICE AND REPORTS ON WELLS

Do not use this form for proposals to drill or to deepen or reentry to a different reservoir.
Use "APPLICATION FOR PERMIT --" for such proposals
SUBMIT IN TRIPLICATE

5. Lease Designation and Serial No. *U 0144869*

6. If Indian, Allottee or Tribe Name

7. If Unit or C.A., Agreement Designation *NATURAL BUTTES UNIT*

1. Type of Well
   - [ ] Oil Well
   - [x] Gas Well
   - [ ] Other

8. Well Name and No. NATURAL BUTTES UNIT 21-20B

2. Name of Operator *ENRON OIL & GAS COMPANY*

9. API Well No. *43-047-30359*

3. Address and Telephone No. *P.O. BOX 250, BIG PINEY, WY 83113* (307) 276-3331

10. Field and Pool or Exploratory Area NATURAL BUTTES/WASATCH

4. Location of Well (Footage, Sec., T., R., M., or Survey Description)
1037' FNL - 1033' FEL (NE/NE)
SECTION 20, T9S, R20E

11. County or Parrish, State *UINTAH, UTAH*

12. CHECK APPROPRIATE BOX(s) TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION	
[x] NOTICE OF INTENT	[ ] ABANDONMENT	[ ] CHANGE OF PLANS
[ ] SUBSEQUENT REPORT	[ ] RECOMPLETION	[ ] NEW CONSTRUCTION
[ ] FINAL ABANDONMENT NOTICE	[ ] PLUGGING BACK	[ ] NON-ROUTINE FRACTURING
	[ ] CASING REPAIR	[ ] WATER SHUT-OFF
	[ ] ALTERING CASING	[x] CONVERSION TO INJECTION
	[ ] OTHER	

(Note: Report results of multiple completion on Well Completions or Recompletion Report and Log Form.)

13. Describe Proposed or Completed Operations (Clearly state all pertinent details and give pertinent dates, including estimated date of starting any proposed work if well is directionally drilled give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work).

Enron Oil & Gas Company proposes to convert the subject well from shut-in gas well to water disposal well. The Underground Injection Control Permit Application is attached for your information and review.

14. I hereby certify that the foregoing is true and correct

SIGNED Katy Carlson TITLE *Regulatory Analyst* DATE 4-1-92

(This space for Federal or State office use)

APPROVED BY TITLE DATE

CONDITIONS OF APPROVAL, IF ANY:

Title 18 U.S.C. Section 1001, makes it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

ENRON
Oil & Gas Company

P.O. Box 250 Big Piney, Wyoming 83113 (307) 276-3331

April 3, 1992

Lease Operators/owner within one (1) mile radius of the subject well per Exhibit I.

RE: PERMIT APPLICATION FOR
WATER DISPOSAL
NATURAL BUTTES UNIT 21-20B
SECTION 20, T9S, R20E
UINTAH COUNTY, UTAH

Gentlemen:

Notice is hereby given of Enron Oil & Gas Company's intent to apply for a permit for water disposal in the subject well. Enron proposes to inject associated produced water from Green River and Wasatch oil and gas wells in Townships 8, 9, and 10 South and Ranges 19, 20, 21, and 22 East into the Green River "H" sand at a depth of 3802'-3825' in the subject well. Anticipated maximum injection pressure will be 1400 psig with a maximum injection volume of 1200 BWPD.

Because the subject well is located on Tribal surface, the permit application will be reviewed and processed through the Environmental Protection Agency. The EPA contact for this application is Mr. Gustav Stolz, JR., P.E., 999 18th Street, Suite 500, Denver, Colorado 80202-2405 (303-293-1416). Opportunity for comment on the permit application will be provided by the EPA and announced following EPA preparation of a draft permit.

Sincerely,

ENRON OIL & GAS COMPANY

CC Parsons
C.C. Parsons
District Manager

JRS/kc

cc: File

ENRON
Oil & Gas Company

Walter C. "Dub" Wilson
Senior Vice President and
Chief Financial Officer

P. O. Box 1188
Houston, Texas 77251-1188
(713) 853-5012

March 25, 1992

Regional Administrator
ENVIRONMENTAL PROTECTION AGENCY, REGION VIII
999 18th Street, Suite 500
Denver, CO 80202-2405

Gentlemen:

We are electing the financial statement demonstration of financial responsibility. Accordingly, we are enclosing the required "Chief Financial Officer's Letter" and a copy of the Enron Oil & Gas Company 1991 Annual Report on Form 10-K which was filed with the Securities and Exchange Commission on March 23, 1992.

Sincerely,

W. C. Wilson

BBB/ps

Enclosures (2)

3486C

CHIEF FINANCIAL OFFICER'S LETTER

U.S. Environmental Protection Agency
Underground Injection Control
Class II Injection Well Operators

This letter contains information submitted as evidence of financial responsibility for the Environmental Protection Agency's underground injection control requirements.

Submitted to: Regional Administrator
Environmental Protection Agency Region VIII
999 18th Street, Suite 500
Denver, CO 80202-2405
(Address of EPA Regional Office)

Submitted for: Enron Oil & Gas Company
(Legal name of owner or operating company)
1400 Smith Street
Houston, Texas 77002
(Business address of owner or operator)

Type of organization: Corporation
(Individual, joint venture, partnership, or corporation)

Date of incorporation: June 12, 1985

State of incorporation: Delaware

Submitted by: Walter C. Wilson
(Name of Chief Financial Officer)

Enron Oil & Gas Company
(Name of firm)

1400 Smith Street
Houston, Texas 77002
(Business address)

I hereby certify that the financial information contained on the following pages is correct and derived from this firm's year-end financial statements prepared in the normal course of business for the latest completed fiscal year ended December 31, 1991.

W. C. Wilson
(Signature of Financial Officer)

3/23/92
(Date)

I. (Firm name) Enron Oil & Gas Company
is the owner or operator of Class II injection wells in the following states within EPA Region VIII :

State names: Wyoming

II. This firm guarantees the plugging and abandonment of injection wells owned or operated by the following subsidiaries:

Subsidiary name:	Subsidiary address:
N/A	

III. This firm is ( ) required ( ) not required to file a Form 10-K with the Securities and Exchange Commission (SEC) for the latest fiscal year.

IV. The fiscal year of this firm ends on (month/day) December 31 . The financial information contained in this letter is derived from this firm's year-end financial statements prepared in the normal course of business for the latest completed fiscal year ended (date) December 31, 1991 .

The name and address of the accounting firm examining these financial statements:

Arthur Andersen & Co.
(Name of accounting firm)

711 Louisiana, Suite 1300, Houston, TX 77002
(Address of accounting firm)

V. The dollar amounts below are stated in ( ) actual (X) thousands of dollars.

Financial Information

Balance Sheet Information:

1.	Current Assets	109,706
2.	Total Assets	1,455,608
3.	Current Liabilities	113,311
4.	Total Liabilities	805,405
5.	Net Worth or Stockholders' Equity	650,203

Income Statement Information:

6.	Depreciation, Depletion, and Amortization	160,885
7.	Net Income	54,934

Calculations:

8.	Total Liabilities less Current Liabilities (Item 4 - Item 3)	692,094
9.	Depreciation, Depletion, and Amortization plus Net Income (Item 6 + Item 7)	215,819
10.	Current Assets less Current Liabilities (Item 1 - Item 3; indicate negative numbers with parentheses)	(3,605)
11.	Current Liabilities divided by Net Worth (Item 3 ÷ Item 5; round to two decimal places)	.17
12.	Total Liabilities less Current Liabilities, all divided by Net Worth (Item 8 ÷ Item 5; round to two decimal places)	1.06
13.	Depreciation, Depletion, and Amortization plus Net Income, all divided by Total Liabilities (Item 9 ÷ Item 4; round to three decimal places)	.268

14. Current Assets less Current Liabilities, all divided by Total Assets (Item 10 ÷ Item 2; round to two decimal places, indicate negative numbers with parentheses) (.0025)

VI. Based on the information in Part V, the company meets or does not meet the financial ratio requirements, as indicated.

	Yes	No
1. Current Liabilities ÷ Net Worth less than 1.0 (Item V-11 less than 1.0)	X	
2. Long-Term Liabilities ÷ Net Worth less than 2.0 (Item V-12 less than 2.0)	X	
3. Net Income greater than zero. (Item V-7 greater than 0)	X	
4. Net Income + depreciation, depletion and amortization total ÷ total liabilities greater than 0.10 (Item V-13 is greater than 0.10)	X	
5. Working Capital ÷ Total Assets greater than -0.10 (Item 14 greater than -0.10)	X	

VII. This firm ( ) has (·) has not received a rating by either Standard and Poor's or Moody's.

The current bond rating of most recent issuance of this firm: BBB/Baa2 (Preliminary)

The name of the rating service: S & P/Moody's

The date of issuance of bond rating: 1991

The date of expiration of bond rating: N/A

	Yes	No	Not Available
VIII. This firm's bond rating by Standard and Poor's is AAA, AA, A, or BBB	X		
This firm's bond rating by Moody's is Aaa, Aa, A, or Baa	X		

EXHIBIT XII

Form Appr 1. OMB No 2040-0042 Approval expires 9-30-86

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, DC 20460

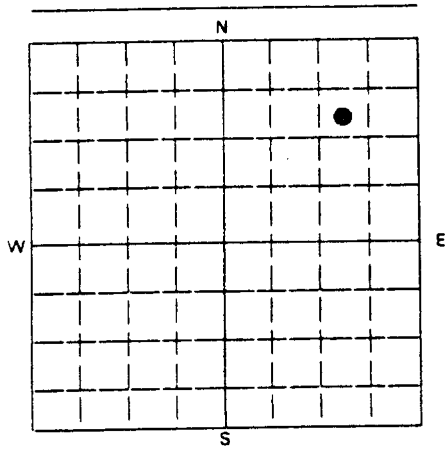
EPA

PLUGGING AND ABANDONMENT PLAN

NAME AND ADDRESS OF FACILITY
NATURAL BUTTES UNIT 21-20B
NE/NE, SECTION 20, T9S, R20E
UINTAH COUNTY, WYOMING

NAME AND ADDRESS OF OWNER/OPERATOR
ENRON OIL & GAS COMPANY
P.O. BOX 250
BIG PINEY, WYOMING 83113

LOCATE WELL AND OUTLINE UNIT ON SECTION PLAT — 640 ACRES



STATE: UTAH | COUNTY: UINTAH | PERMIT NUMBER:

SURFACE LOCATION DESCRIPTION
NE ¼ OF NE ¼ OF NE ¼ SECTION 20 TOWNSHIP 9S RANGE 20E

LOCATE WELL IN TWO DIRECTIONS FROM NEAREST LINES OF QUARTER SECTION AND DRILLING UNIT

Surface Location 1037 ft. from (N/S) N Line of quarter section
and 1033 ft. from (E/W) E Line of quarter section

TYPE OF AUTHORIZATION
☒ Individual Permit
☐ Area Permit
☐ Rule

Number of Wells 1

WELL ACTIVITY
☐ CLASS I
☒ CLASS II
☒ Brine Disposal
☐ Enhanced Recovery
☐ Hydrocarbon Storage
☐ CLASS III

Lease Name NATURAL BUTTES UNIT

Well Number NBU 21-20B

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT(LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
9-5/8"	36.0#		196'	12-1/4"
4-1/2"	11.6#		7025'	7-7/8"

METHOD OF EMPLACEMENT OF CEMENT PLUGS
☒ The Balance Method
☐ The Dump Bailer Method
☐ The Two-Plug Method
☒ Other CEMENT RETAINER

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inches)	4-1/2"	4-1/2"	& 9-5/8"	(Perforated @ 200' in 4-1/2" csg.)			
Depth to Bottom of Tubing or Drill Pipe (ft.) (Cmt. retainer)	3750	200					
Sacks of Cement To Be Used (each plug) Pumped below retainer	50	100					
Slurry Volume To Be Pumped (cu. ft.)	57.5	115					
Calculated Top of Plug (ft.) 50' left on top of retainer	3700	Surface					
Measured Top of Plug (if tagged ft.)							
Slurry Wt. (Lb./Gal.)	15.6	15.6					
Type Cement or Other Material (Class III)	Class G	Class G					

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To
3802'	3825'	6592'	6594'
6092'	6094'	6907'	6909'
6111'	6113'	6914'	6916'
6128'	6130'		

Estimated Cost to Plug Wells

CERTIFICATION

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

NAME AND OFFICIAL TITLE *(Please type or print)*	SIGNATURE	DATE SIGNED

Form 4 UIC

EPA

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PERMIT APPLICATION
(Collected under the authority of the Safe Drinking Water Act. Sections 1421, 1422, 40 CFR 144)

Form Approved. OMB No. 2040-0042. Expires 9-30-86

I. EPA ID NUMBER

		T/A	C
U			

READ ATTACHED INSTRUCTIONS BEFORE STARTING
FOR OFFICIAL USE ONLY

Application approved mo	day	year	Date Received mo	day	year	Permit/Well Number	Comments

II. FACILITY NAME AND ADDRESS

Facility Name: NATURAL BUTTES UNIT 21-20B
Street Address: NENE, SECTION 20, T9S, R20E
City:
State: UT
ZIP Code:

III. OWNER/OPERATOR AND ADDRESS

Owner/Operator Name: ENRON OIL & GAS COMPANY
Street Address: P.O. BOX 250
City: BIG PINEY
State: WY
ZIP Code: 83113

IV. OWNERSHIP STATUS *(Mark 'x')*

☐ A. Federal ☐ B. State ☐ C. Private
☐ D. Public ☒ E. Other *(Explain)* BLM in trust for Ute Indian Tribe

V. SIC CODES

1311

VI. WELL STATUS *(Mark 'x')*

☐ A. Operating — Date Started: mo / day / year
☒ B. Modification/Conversion
☐ C. Proposed

VII. TYPE OF PERMIT REQUESTED *(Mark 'x' and specify if required)*

☒ A. Individual	☐ B. Area	Number of Existing wells	Number of Proposed wells	Name(s) of field(s) or project(s)
			1	NATURAL BUTTES UNIT 21-20B/NATURAL BUTTES

VIII. CLASS AND TYPE OF WELL *(see reverse)*

A. Class(es) *(enter code(s))*	B. Type(s) *(enter code(s))*	C. If class is "other" or type is code 'x,' explain	D. Number of wells per type (if area permit)
CLASS II	D		

IX. LOCATION OF WELL(S) OR APPROXIMATE CENTER OF FIELD OR PROJECT

A. Latitude Deg	Min	Sec	B. Longitude Deg	Min	Sec	Twsp	Range	Sec	¼ Sec	Feet from	Line	Feet from	Line
						9S	20E	20	NE	1037	N	1033	E

X. INDIAN LANDS *(Mark 'x')*

☒ Yes ☐ No

XI. ATTACHMENTS

(Complete the following questions on a separate sheet(s) and number accordingly; see instructions)

FOR CLASSES I, II, III (and other classes) complete and submit on separate sheet(s) Attachments A — U (pp 2-6) as appropriate. Attach maps where required. List attachments by letter which are applicable and are included with your application:

XII. CERTIFICATION

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

A. Name and Title *(Type or Print)*: Douglas Weaver - VP Gen MGR
B. Phone No. *(Area Code and No.)*: 303-293-2525
C. Signature: [signature]
D. Date Signed: 4/6/92

ATTACHMENTS TO FORM 4 (UIC PERMIT APPLICATION)
NATURAL BUTTES UNIT 21-20B
NE/NE SECTION 20, T9S, R20E
UINTAH COUNTY, UTAH

Attachment A: The area of review for the proposed injection well is based on a fixed radius of one (1) mile. Surface within the area of review is controlled by the Bureau of Land Management in trust for the Ute Indian Tribe. In accordance with Rule 40 CFR 147.1355 (Part b), attached as Exhibits I and IA are a list of lease operators/owners within a one (1) mile radius of the proposed injection well and an affidavit verifying that each has been notified of Enron Oil and Gas Company's intent to apply for an injection permit.

Attachment B: Attached as Exhibits II, IIA, and IIB are an ownership map of the area of review, topographic map of the area of review, and a disposal facility diagram.

Attachment C: Attached as Exhibit III is a Well Data Sheet listing pertinent information on wells located within the area of review.

Attachment E: Within the area of review of the proposed injection well, the maximum depth of USDW's is 800' in the Uintah formation. Please refer to attached Exhibit IV, Generalized Map of Moderately Saline Ground Water In The Southern Uintah Basin, Utah.

Attachment G: The injection interval in the proposed disposal well is in the Green River formation "H" sand. The top of the "H" sand is at a depth of 3798'KB in the subject well and is 30' thick. See attached Exhibit V (Mud Log) and Exhibit VI (Densilog). A step rate test was conducted on 1/25/92 and indicated a formation fracture pressure of 1680 psi. See attached Exhibit VII (Dowell Well Treatment Report). An uncontaminated sample of injection zone fluid was obtained prior to the step rate test and the analysis of this fluid is attached as Exhibit VIII.

Attachment H: Proposed operating data for the injection well is as follows:

1. Maximum daily rate and volume: 50 BPH (1200 BPD)
   Average daily rate and volume: 15 BPH (360 BPD)
2. Maximum injection pressure: 1400 psi
   Average injection pressure: 800 psi
3. Annulus fluid: Inhibited fresh water
4. Injection fluid characteristics: See attached representative water analyses of formation waters from wells in the areas from which water will be gathered for disposal (Exhibit IX).

Attachment M: Attached as Exhibit X is a wellbore diagram of the subject well including the downhole mechanical configuration which will be utilized for injection. Attached as Exhibit XI is the cement bond log for the subject well.

Attachment Q: Attached as Exhibit XII is a proposed plugging and abandonment plan for the subject well.

Attachment R: Attached as Exhibit XIII is the financial statement and Form 10-K for Enron Oil and Gas Company, demonstrating the Company's financial means for plugging and abandonment of the subject well.

Attachment U: Enron Oil and Gas Company proposes to use the subject well for disposal of associated Green River and Wasatch formation water being produced from numerous gas and oil wells in Townships 8, 9, & 10 South, Ranges 19, 20, 21, & 22 East, Uintah Co., Utah. The produced water will be transported via vacuum truck from the source wells to storage tanks located at the disposal site. The produced water will then be filtered and injected down tubing below a packer into the Green River "H" sand at pressures below formation fracture pressure. Annulus pressures will be monitored during injection and the annulus above the the packer pressure tested periodically to verify casing and packer integrity. An API TDS level of 42000+ mg/l was measured on uncontaminated formation water samples taken from swab tests of the "H" sand in the subject well on 1/24/92.

EXHIBIT I

LEASE OPERATORS/OWNERS WITHIN
1 MILE RADIUS OF NBU 21-20B

1. Coastal Oil & Gas Corporation, Attention: Jon R. Nelson, Box 749, Denver, Colorado 80201-0749.

2. Uinta/Taylor Fund, c/o Derry Moore, Managing Partner, Box 2366, Roswell, New Mexico 88201.

3. Bar Mesa Resources, Inc., Box 213, Roosevelt, Utah 84066.

4. Equitable Resources Energy Company, c/o Balcron Oil Company, Box 21017, Billings, Montana 59104.

5. Transfuel Resources Company, 15995 N. Barkers Landing, Suite 300, Houston, Texas 77079.

6. Lomax Exploration Company, 13405 N.W. Freeway, Suite 314, Houston, Texas 77040.

7. Franzheim Investment Company, 2700 Post Oak Blvd., Suite 2370, Houston, Texas 77065.

8. JDH Oil Company, Inc., 2222 North Fountain Valley, Missouri City, Texas 77459.

9. Charles D. Fitch, Box 22145, Houston, Texas 77227-2145.

10. W.G. DeArman, 1021 Niels Esperson Building, Houston, Texas 77002.

11. Texaco Inc., Attention: Wayne Ziemianski, Box 2100, Denver, Colorado 80201.

12. J.V. Atkinson, Doug Nix Farms, Inc., Paul Gora, Nicholas Mallis, M.D., George C. Peverley III, Gene Rahll, Daniel H. Redding, c/o JVA Operating Company, Inc., Box 3634, Midland, Texas 79702.

EXHIBIT IA

STATE OF WYOMING)
) ss
COUNTY OF SUBLETTE)

AFFIDAVIT

C.C. Parsons, of lawful age, being first duly sworn upon oath, deposes and says that:

He is the District Manager of Enron Oil & Gas Company, of Big Piney, Wyoming, and that to the best of his knowledge, Enron Oil & Gas Company and the lease operators/owners on attached Exhibit I are the only lease operators/owners within a one-mile radius of the subject well:

NATURAL BUTTES UNIT 21-20B
NE/NE, SECTION 20, T9S, R20E
UINTAH COUNTY, UTAH

That on the 3rd day of April 1992, he placed in the United States Mail, with postage prepaid, a copy of the attached letter of intent to the first eleven lease operators/owners listed on Exhibit I and that on April 8, 1992, he placed in the U.S. Mail with postage prepaid, a copy of the attached letter of intent to the lease operators/owners listed twelfth on attached Exhibit I.

Said envelope which contained these instruments was addressed to the lease operators/owners on attached Exhibit I.

Further this affiant saith not.

C C Parsons

C.C. Parsons
District Manager

Subscribed and sworn to before me this 8th day of April 1992.

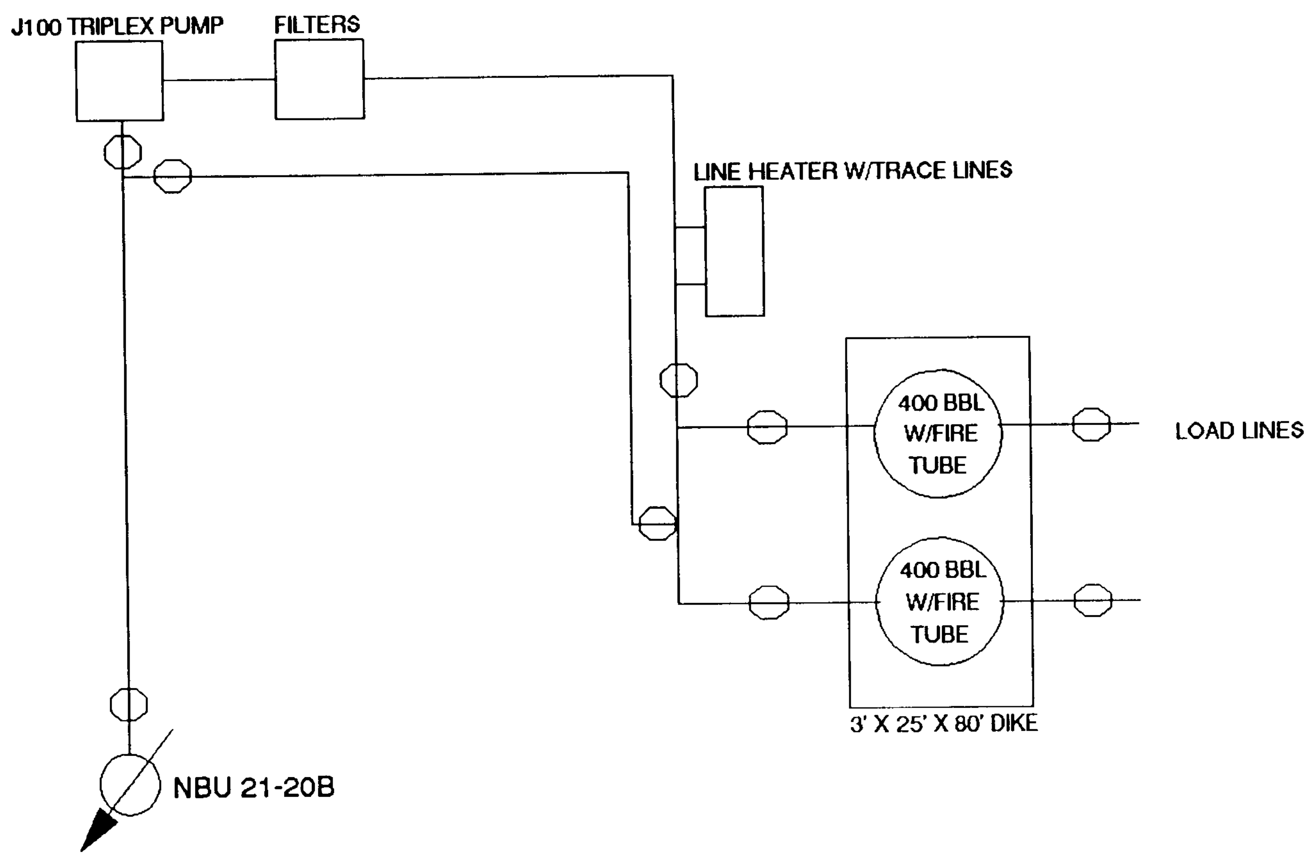
Georgia Costello
Notary Public

MY COMMISSION EXPIRES JANUARY 23, 1993.

GEORGIA COSTELLO
Notary Public - State of Wyoming
My commission expires

EXHIBIT IIB

PROPOSED DISPOSAL FACILITY DIAGRAM



WELL TREATMENT REPORT

DS EXHIBIT VI.

DS-494-A PRINTED IN U.S.A. DOWELL SCHLUMBERGER INCORPORATED

DATE 1-25-92

WELL NAME AND NUMBER: NBU 21-20 B
LOCATION (LEGAL): SEC 20 T9S R20E
DS LOCATION: Vernal Utah
TREATMENT NUMBER: 15-03 7838

POOL/FIELD: Natural Buttes
FORMATION: Green River
BOTTOM HOLE TEMPERATURE:
AGE OF WELL: NEW ☐ REWORK ☒
TYPE OF WELL: OIL ☐ GAS ☐ WATER ☐ INJ. ☒

COUNTY/PARISH: Uintah
STATE: Utah
ALLOWABLE PRESSURE: TBG: 2500 CSG: —

TYPE OF SERVICE: ☐ MATRIX TREATMENT ☐ FRACTURING ☐ SAND CONTROL ☒ OTHER
PRIMARY TREATING FLUID: H20

OPERATOR NAME: Enron

SERVICE INSTRUCTIONS: Furnish equipment + personnel To do Step Rate Test As per Comp Rep Inst

CASING SIZE	WT	DEPTH
4 1/2	11.6	4000 T

TUBING SIZE	WT	DEPTH
2 3/8	4.7	3800

PACKER TYPE: — PACKER DEPTH: —
TUBING VOLUME: 14.7 ANNULAR VOL: —
OPEN HOLE: — CASING VOL: —
DISPLACEMENT: —

PERFORATED INTERVALS

TOP	TO	BOTTOM	NO. OF HOLES
3802	TO	3825	46
	TO		
	TO		
	TO		
	TO		
	TO		
	TO		

PERF. DIAMETER — IN.
PERFORATED INTERVAL TOTAL 23 FT.

JOB DONE DOWN: C. TBG. ☐ TUBING ☒ CASING ☐ ANNULUS ☐ BOTH ☐

FOR CONVERSION PURPOSES 24 BBLS EQUALS 1000 GALLONS —
ARRIVED ON LOCATION: 0600 LEFT LOCATION: 1100

TIME	TYPE OF FLUID	RATE BPM	CO_2 - N_2 RATE	INCREMENT VOL. BBLS	CUM. VOL. BBLS	PROP TYPE	PROP #/GAL	PRESSURE CSG.	PRESSURE TBG	NOTATIONS
0745										Pre-Job Safety Meeting GD
0751										Pressure Test To 2500 psi
0758	H20	2	—	2.3	2.3	—	—	—	1000	Fill Hole
0800	11	.25		.25	.25	—	—	—	600	Start Rate at .25
0801	11	.25		.25	.50	—	—	—	700	Pressure & Rate
0802	11	.25		.25	.75	—	—	—	740	
0803	11	.25		.25	1.0	—	—	—	790	
0804	11	.25		.25	1.25	—	—	—	800	
0805	11	.25		.25	1.50	—	—	—	830	
0806	11	.25		.25	1.75	—	—	—	850	
0807	11	.25		.25	2.0	—	—	—	870	
0808	11	.25		.25	2.25	—	—	—	880	
0809	11	.25		.25	2.50	—	—	—	910	
0810	11	.25		.25	2.75	—	—	—	940	
0811	11	.25		.25	3.0	—	—	—	950	
0812	11	.25		.25	3.25	—	—	—	980	
0813	11	.25		.25	3.50	—	—	—	1030	
0814	11	.25		.25	3.75	—	—	—	1060	
0815	11	.25		.25	4.0	—	—	—	1080	
0816	11	.25		.25	4.25	—	—	—	1110	
0817	11	.25		.25	4.50	—	—	—	1140	

BPM AVERAGE INJECTION RATES: FLUID — NITROGEN — CARBON DIOXIDE — TOTAL W/PROP —

VOLUME FLUID INJECTED: WATER/ACID 130 BBLS OIL — BBLS NITROGEN — CCF CARBON DIOXIDE — TONS

TREATING PRESSURE SUMMARY: MAXIMUM — FINAL — AVERAGE — IMMED. S.D.P. 600 15 MIN S.I.P. 270

QUANTITY PROPPANT PLACED: TOTAL INJECTED — LBS TOTAL ORDERED/DESIGNED — LBS

PRODUCTION PRIOR TO THIS TREATMENT ☐ Test ☐ Stabilized

PAD VOLUME — GALS % PAD —

FRACTURE GRADIENT —

CUSTOMER REPRESENTATIVE: Tom Hufford
DS SERVICE SUPERVISOR: Gary Daniels

WELL TREATMENT REPORT
SUPPLEMENTAL LOG
DS-494-1-A PRINTED IN U.S.A.

DS
DOWELL SCHLUMBERGER INCORPORATED

DATE 1-25-92

CUSTOMER WELL NAME AND NUMBER: NBU 21-20 B
LOCATION (LEGAL):
POOL/FIELD: Natural Buttes
TREATMENT NUMBER: 5-03 7838
PAGE 2 OF 5 PAGES

TIME (0001 to 2400)	TYPE OF FLUID	RATE BPM	CO2 - N2 RATE	INCREMENT VOL. BBLS	CUM. VOL. BBLS	PROP TYPE	PROP #/GAL	CSG.	TBG	NOTATIONS
0818	H2O	.25	—	.25	4.75	—	—	—	1160	Pressure & Rate
0819		.25	—	.25	5.0	—	—	—	1180	
0820		.25	—	.25	5.25	—	—	—	1210	
0821		.25	—	.25	5.5	—	—	—	1230	
0822		.25	—	.25	5.75	—	—	—	1240	
0823		.25	—	.25	6.0	—	—	—	1270	
0824		.25	—	.25	6.25	—	—	—	1270	
0825		.25	—	.25	6.5	—	—	—	1270	
0826		.25	—	.25	6.75	—	—	—	1280	
0827		.25	—	.25	7.0	—	—	—	1290	
0828		.25	—	.25	7.25	—	—	—	1300	
0829		.25	—	.25	7.5	—	—	—	1300	
0830		.35	—	.25	7.75	—	—	—	1310	
0831		.25	—	.25	8.0	—	—	—	1310	
0832		.25	—	.25	8.25	—	—	—	1320	
0833		.25	—	.25	8.5	—	—	—	1330	
0834		.25	—	.25	8.75	—	—	—	1340	
0835		.25	—	.25	9.0	—	—	—	1350	
0836		.5	—	.5	.5	—	—	—	1660	Increase Rate to .5
0837		.5	—	.5	1	—	—	—	1660	Pressure & Rate
0838		.5	—	.5	1.5	—	—	—	1660	
0839		.5	—	.5	2.0	—	—	—	1660	
0840		.5	—	.5	2.5	—	—	—	1680	
0841		.5	—	.5	3.0	—	—	—	1680	
0842		.5	—	.5	3.5	—	—	—	1680	
0843		.5	—	.5	4.0	—	—	—	1680	
0844		.5	—	.5	4.5	—	—	—	1680	
0845		.5	—	.5	5.0	—	—	—	1680	
0846		.5	—	.5	5.5	—	—	—	1680	
0847		.5	—	.5	6.0	—	—	—	1680	
0848		.5	—	.5	6.5	—	—	—	1680	
0849										Increase Rate to .75
0850		.75	—	.75	.75	—	—	—	1660	Pressure & Rate
0851		.75	—	.75	1.5	—	—	—	1680	
0852		.75	—	.75	2.25	—	—	—	1680	
0853		.75	—	.75	3.0	—	—	—	1660	

WELL TREATMENT REPORT
SUPPLEMENTAL LOG
DS-494-1-A PRINTED IN U.S.A.

DS
DOWELL SCHLUMBERGER INCORPORATED

DATE 1-28-92

CUSTOMER WELL NAME AND NUMBER: NBU 20-20 B
LOCATION (LEGAL):
POOL/FIELD: Natural Buttes
TREATMENT NUMBER 15-03 7838
PAGE 3 OF 5 PAGES

TIME (0001 to 2400)	INJECTION RECORD: TYPE OF FLUID	RATE BPM	CO_2 - N_2 RATE	INCREMENT VOL. BBLS	CUM. VOL. BBLS	PROP TYPE	PROP $/GAL	PRESSURE: CSG.	TBG.	NOTATIONS
0854	H_2O	.75	—	.75	3.75	—	—	—	1670	Pressure & Rate
0855		.75	—	.75	4.5	—	—	—	1670	
0856		.75	—	.75	5.25	—	—	—	1670	
0857		.75	—	.75	6.0	—	—	—	1640	
0858		.75	—	.75	6.75	—	—	—	1670	
0859		.75	—	.75	7.5	—	—	—	1670	
0900		.75	—	.75	8.25	—	—	—	1670	
0901		.75	—	.75	9.0	—	—	—	1670	
0902		.75	—	.75	9.75	—	—	—	1670	
0903		1	—	1	1	—	—	—	1680	Increase Rate To 1 BPM
0904		1	—	1	2	—	—	—	1680	Pressure & Rate
0905		1	—	1	3	—	—	—	1680	
0906		1	—	1	4	—	—	—	1630	
0907		1	—	1	5	—	—	—	1630	
0908		1	—	1	6	—	—	—	1630	
0909		1	—	1	7	—	—	—	1600	
0910		1	—	1	8	—	—	—	1580	
0911		1	—	1	9	—	—	—	1580	
0912		1	—	1	10	—	—	—	1580	
0913		1	—	1	11	—	—	—	1560	
0914		1	—	1	12	—	—	—	1550	
0915		1	—	1	13	—	—	—	1530	
0916		1	—	1	14	—	—	—	1520	
0917		1	—	1	15	—	—	—	1510	
0918										Increase Rate To 2 BPM
0919		2	—	2	2	—	—	—	1750	Pressure & Rate
0920		2	—	2	4	—	—	—	1780	
0921		2	—	2	6	—	—	—	1770	
0922		2	—	2	8	—	—	—	1760	
0923		2	—	2	10	—	—	—	1750	
0924		2	—	2	12	—	—	—	1740	
0925		2	—	2	14	—	—	—	1740	
0926		2	—	2	16	—	—	—	1740	
0927		2	—	2	18	—	—	—	1740	
0928		2	—	2	20	—	—	—	1720	
0929		2	—	2	22	—	—	—	1700	

SENT BY: XEROX Telecopier 7017; 1-25-92 ; 3:25PM ; VERNAL UTAH→ ENRON O&G CO.;# 7/ 7

WELL TREATMENT REPORT
SUPPLEMENTAL LOG
DS-494-1-A PRINTED IN U.S.A

DS
DOWELL SCHLUMBERGER INCORPORATED

DATE 1-25-92

CUSTOMER WELL NAME AND NUMBER: NBU 21-20B
LOCATION (LEGAL):
POOL/FIELD: Natural Buttes
TREATMENT NUMBER: 5-03 7838
PAGE 5 OF 5 PAGES

TIME (0001 to 2400)	TYPE OF FLUID	RATE BPM	CO_2 - N_2 RATE	INCREMENT VOL. BBLS.	CUM. VOL. BBLS.	PROP TYPE	PROP #/GAL.	CSG.	TBG	NOTATIONS
1006	H2O	1.5	—	1.5	25.5	—	—	—	1440	Pressure & Rate
1007		"	—	"	27	—	—	—	"	
1008		"	—	"	28.5	—	—	—	"	
1009		"	—	"	30	—	—	—	"	
1010		"	—	"	31.5	—	—	—	"	
1011		"	—	"	33	—	—	—	"	
1012		"	—	"	34.5	—	—	—	"	
1013		"	—	"	36	—	—	—	"	
1014		"	—	"	37.5	—	—	—	"	
1015		"	—	"	39	—	—	—	"	
1016		"	—	"	40.5	—	—	—	"	
1017		"	—	"	42	—	—	—	"	
1018		"	—	"	43.5	—	—	—	"	
1019		"	—	"	45	—	—	—	"	
1020		"	—	"	46.5	—	—	—	"	
1021		"	—	"	48	—	—	—	"	
1022		"	—	"	49.5	—	—	—	"	
1023		"	—	"	51	—	—	—	"	
1024		"	—	"	52.5	—	—	—	"	
1025		"	—	"	54	—	—	—	"	
1026		"	—	"	55.5	—	—	—	"	
1027		"	—	"	57	—	—	—	"	
1028		"	—	"	58.5	—	—	—	"	
1029		"	—	"	60	—	—	—	"	
1030		"	—	"	61.5	—	—	—	1440	
1031										Shut Down
										ISIP 600
										5 Min. 300
										10 Min 290
										15 Min 270
1050										Rig Down DS

WELL TREATMENT REPORT SUPPLEMENTAL LOG

DS-494-1-A PRINTED IN U.S.A.

DOWELL SCHLUMBERGER INCORPORATED

DATE 1-25-92

CUSTOMER WELL NAME AND NUMBER: NBU 21-20 B

LOCATION (LEGAL):

POOL/FIELD: Natural Buttes

TREATMENT NUMBER 15-03 7838

PAGE 4 OF 5 PAGES

TIME (0001 to 2400)	TYPE OF FLUID	RATE BPM	CO_2 - N_2 RATE	INCREMENT VOL. BBLS	CUM. VOL. BBLS	PROP TYPE	PROP #/GAL	PRESSURE CSG.	PRESSURE TBG	NOTATIONS
0930	H2O	2	—	2	24	—	—	—	1690	Pressure & Rate
0931		2	—	2	26	—	—	—	1680	
0932										Decrease ~~Rate .25~~
0933										
0934		.25	—	.25		—	—	—	580	Pressure & Rate
0935		.25	—	.50		—	—	—	560	
0936		.25	—	.75		—	—	—	560	
0937		.25	—	1.0		—	—	—	550	
0938		.25	—	1.25		—	—	—	540	
0939		.25	—	1.5		—	—	—	540	
0940		.25	—	1.75		—	—	—	540	
0941		.25	—	2.0		—	—	—	540	
0942		.25	—	2.25		—	—	—	540	
0943		.25	—	2.5		—	—	—	540	
0944		.25	—	2.75		—	—	—	540	
0945		.25	—	3.0		—	—	—	540	
0946		.25	—	3.25		—	—	—	540	
0947		.25	—	3.5		—	—	—	540	
0948		.25	—	3.75		—	—	—	540	
0949										Increase Rate to 1.5 BPm
0950		1.5	—	1.5	1.5	—	—	—	1420	Pressure & Rate
0951		1.5	—	1.5	3	—	—	—	1440	
0952		1.5	—	1.5	4.5	—	—	—	1440	
0953		1.5	—	1.5	6	—	—	—	1440	
0954		1.5	—	1.5	7.5	—	—	—	1440	
0955		1.5	—	1.5	9	—	—	—	1440	
0956		1.5	—	1.5	10.5	—	—	—	1440	
0957		1.5	—	1.5	12	—	—	—	1440	
0958		1.5	—	1.5	13.5	—	—	—	1440	
0959		1.5	—	1.5	15	—	—	—	1440	
1000		1.5	—	1.5	16.5	—	—	—	1440	
1001		1.5	—	1.5	18	—	—	—	1440	
1002		1.5	—	1.5	19.5	—	—	—	1440	
1003		1.5	—	1.5	21	—	—	—	1440	
1004		1.5	—	1.5	22.5	—	—	—	1440	
1005		1.5	—	1.5	24	—	—	—	1440	

K+E 5 X 5 TO THE INCH • 7 X 10 INCHES KEUFFEL & ESSER CO. MADE IN U.S.A. 46 0410

STEP RATE TEST (1/25/92)

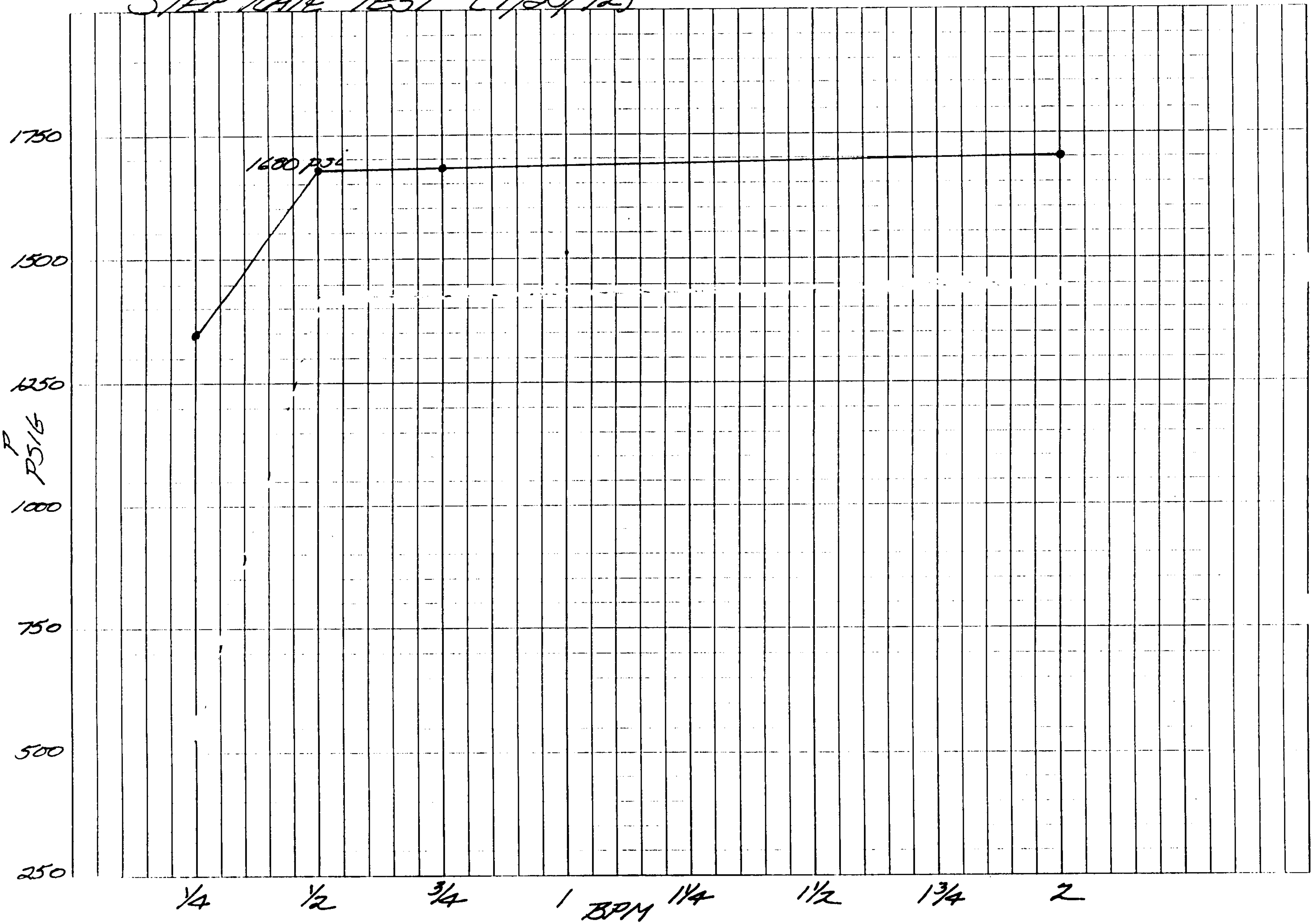


EXHIBIT IX

SOONER CHEMICAL SPECIALTIES, INC.

SOONER CHEMICALS

P. O. Box 711 SEMINOLE, OKLAHOMA 74868 Phone (405) 382-2000

WATER ANALYSIS REPORT

COMPANY Belco Petroleum ADDRESS 47-27B DATE: 8-13-80

SOURCE Natural Buttes 47-27-B DATE SAMPLED 8-11-80 ANALYSIS NO. 4

T-9S,R20E,Sec.27,(SW-SE)

Analysis		Mg/L			*Meq/L	
1. PH	6.5					
2. H_2S (Qualitative)	Neg.					
3. Specific Gravity	1.010					
4. Dissolved Solids			22,050			
5. Suspended Solids						
6. Phenolphthalein Alkalinity ($CaCO_3$)						
7. Methyl Orange Alkalinity ($CaCO_3$)			580			
8. Bicarbonate (HCO_3)		HCO_3	708	÷61	12	HCO_3
9. Chlorides (Cl)		Cl	9,381	÷35.5	264	Cl
10. Sulfates (SO_4)		SO_4	675	÷48	14	SO_4
11. Calcium (Ca)		Ca	296	÷20	15	Ca
12. Magnesium (Mg)		Mg	74	÷12.2	6	Mg
13. Total Hardness ($CaCO_3$)			1,043			
14. Total Iron (Fe)			10			
15. Barium (Qualitative)			0			
16.						

*Milli equivalents per liter

PROBABLE MINERAL COMPOSITION

*			*
15	Ca	HCO_3	12
6	Mg	SO_4	14
269	Na	Cl	264

Compound	Equiv. Wt.	X	Meq/L	=	Mg/L
$Ca(HCO_3)_2$	81.04		12		972
$CaSO_4$	68.07		3		204
$CaCl_2$	55.50				
$Mg(HCO_3)_2$	73.17				
$MgSO_4$	60.19		6		361
$MgCl_2$	47.62				
$NaHCO_3$	84.00				
Na_2SO_4	71.03		5		355
NaCl	58.46		264		15,433

Saturation Values	Distilled Water 20°C
$CaCO_3$	13 Mg/L
$CaSO_4 \cdot 2H_2O$	2,090 Mg/L
$MgCO_3$	103 Mg/L

Wasatch perfs

REMARKS Sample taken from the following perf's: Holes per foot

Perfs	Holes per foot
6,923-6,925	2
6,456-6,458	4
6,469-6,471	4
6,258-6,260	4

SOONER CHEMICALS

SOONER CHEMICAL SPECIALTIES, INC.

Post Office Box 1436 Roosevelt, Utah 84066 Phone (801) 722-3386

WATER ANALYSIS REPORT

COMPANY [illegible] ADDRESS ______ DATE: [illegible]

SOURCE NBB-11-20 Sec. 20, T9S, R22E DATE SAMPLED [illegible] ANALYSIS NO. [illegible]

	Analysis	Mg/l (ppm)		*Meq/l	
1. PH	[illegible]				
2. H_2S (Qualitative)					
3. Specific Gravity	1.020				
4. Dissolved Solids		[illegible]			
5. Suspended Solids					
6. Anaerobic Bacterial Count	C/Ml				
7. Methyl Orange Alkalinity ($CaCO_3$)		[illegible]			
8. Bicarbonate (HCO_3)	HCO_3	[illegible]	÷61	5	HCO_3
9. Chlorides (Cl)	Cl	[illegible]	÷35.5	[illegible]	Cl
10. Sulfates (SO_4)	SO_4	1,500	÷48	31	SO_4
11. Calcium (Ca)	Ca	[illegible]	÷20	[illegible]	Ca
12. Magnesium (Mg)	Mg	[illegible]	÷12.2	2	Mg
13. Total Hardness ($CaCO_3$)		[illegible]			
14. Total Iron (Fe)		[illegible]			
15. Barium (Qualitative)		[illegible]			
16. Phosphate Residuals					

*Milli equivalents per liter

PROBABLE MINERAL COMPOSITION

18	Ca		HCO₃	5
[illegible]	Mg		SO_4	[illegible]
375	Na		Cl	359

Compound	Equiv. Wt.	X	Meq/l	=	Mg/l
$Ca(HCO_3)_2$	81.04		5		405
$CaSO_4$	68.07		13		884
$CaCl_2$	55.50				
$Mg(HCO_3)_2$	73.17				
$MgSO_4$	60.19		2		[illegible]
$MgCl_2$	47.62				
$NaHCO_3$	84.00				
Na_2SO_4	71.03		16		1,136
NaCl	58.46		[illegible]		[illegible]

Saturation Values	Distilled Water 20°C
$CaCO_3$	13 Mg/l
$CaSO_4 \cdot 2H_2O$	2,090 Mg/l
$MgCO_3$	103 Mg/l

REMARKS [illegible] Perfs 5421-6570'

Produced water (Wasatch)

SOONER CHEMICALS

SOONER CHEMICAL SPECIALTIES, INC.

P.O. Box 711 SEMINOLE, OKLAHOMA 74868 Phone (405) 382-2000
P.O. Box 696 GRAND JUNCTION, COLORADO 81502 Phone (303) 858-9765
P.O. Box 1436 ROOSEVELT, UTAH 84066 Phone (801) 722-5386

WATER ANALYSIS REPORT

COMPANY ______ ADDRESS ______ DATE: ______

SOURCE 216-35 VBU Sec. 35, T9S, R22E DATE SAMPLED ______ ANALYSIS NO. ______

	Analysis	Mg/l (ppm)		*Meq/l	
1. PH					
2. H_2S (Qualitative)					
3. Specific Gravity					
4. Dissolved Solids					
5. Suspended Solids					
6. Anaerobic Bacterial Count	C/Ml				
7. Methyl Orange Alkalinity ($CaCO_3$)					
8. Bicarbonate (HCO_3)	HCO_3		÷61		HCO_3
9. Chlorides (Cl)	Cl		÷35.5		Cl
10. Sulfates (SO_4)	SO_4		÷48		SO_4
. Calcium (Ca)	Ca		÷20		Ca
12. Magnesium (Mg)	Mg		÷12.2		Mg
13. Total Hardness ($CaCO_3$)					
14. Total Iron (Fe)					
15. Barium (Qualitative)					
16. Phosphate Residuals					

*Milli equivalents per liter

PROBABLE MINERAL COMPOSITION

Compound	Equiv. Wt.	X Meq/l	= Mg/l
$Ca(HCO_3)_2$	81.04		
$CaSO_4$	68.07		
$CaCl_2$	55.50		
$Mg(HCO_3)_2$	73.17		
$MgSO_4$	60.19		
$MgCl_2$	47.62		
$NaHCO_3$	84.00		
Na_2SO_4	71.03		
NaCl	58.46		

Ca	←	HCO_3
Mg	→	SO_4
Na	→	Cl

Saturation Values	Distilled Water 20° C
$CaCO_3$	13 Mg/l
$CaSO_4 \cdot 2H_2O$	2,090 Mg/l
$MgCO_3$	103 Mg/l

REMARKS Perfs 6761-7176' (Wasatch)
Produced water

Western Atlas International

CORE LABORATORIES

01-08-1992

LAB #: 912965-1

ENRON OIL & GAS COMPANY

WELL #: 1-34
COUNTY: Uintah
STATE: Utah
FORMATION:
DATE SAMPLED: 1/8/92
REMARKS: Produced water

FIELD: Old Squaw Crossing
LOCATION: Sec. 34, T10S, R19E
INTERVAL: 5078-5340 (Wasatch)
SAMPLE ORIGIN: OLD SQUAWS CROSSING

	MG/L	MEQ/L
SODIUM	8300	361.05
POTASSIUM	361	9.24
CALCIUM	570	28.44
MAGNESIUM	88	7.23
TOTAL CATIONS		405.97

	MG/L	MEQ/L
SULFATE	6880	143.10
CHLORIDE	8997	253.72
CARBONATE	0	0.00
BICARBONATE	525	8.60
HYDROXIDE	0	0.00
TOTAL ANIONS		405.42

	MG/L
CALC. SODIUM	8287
NACL EQUIVALENT	23420
CALC TDS* @356 F	25454
API TDS* @221 F	25721

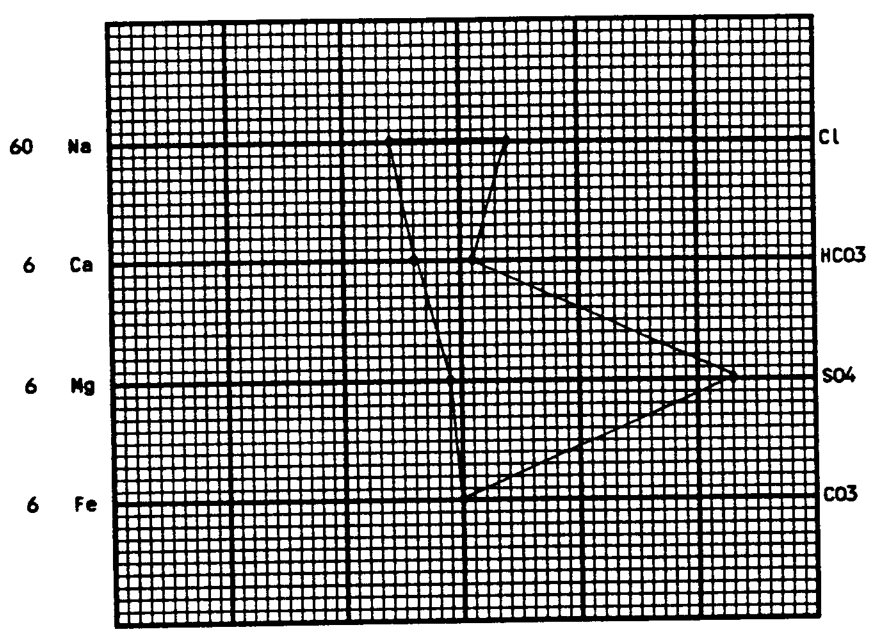
SPECIFIC RESISTANCE AT 68F (OHM-M):
OBSERVED 0.35

OBSERVED pH 7.5

* TOTAL DISSOLVED SOLIDS

WATER ANALYSIS PATTERN
Scale
MEQ per Unit

(Na value in graph includes Na and K)



NOTE: MG/L = milligrams per liter
MEQ/L = milligram equivalent per liter

Sodium Chloride equivalent by Dunlap & Hawthorne - calculation from components

APPROVED BY: [signature]

SOONER CHEMICALS

SOONER CHEMICAL SPECIALTIES, INC

P. O. Box 711 SEMINOLE, OKLAHOMA 74868 Phone (405) 382-2000

WATER ANALYSIS REPORT

COMPANY Belco Development ADDRESS Vernal, Utah DATE 8-5-81

SOURCE NDU 12-21 Natural Duck SEC. 21, T9S, R20E DATE SAMPLED 8-3-81 ANALYSIS NO. 015

Analysis			Mg/L		*Meq/L	
1. PH	8.4					
2. H_2S (Qualitative)	2.5					
3. Specific Gravity	1.025					
4. Dissolved Solids						
5. Suspended Solids						
6. Phenolphthalein Alkalinity ($CaCO_3$)						
7. Methyl Orange Alkalinity ($CaCO_3$)			400			
8. Bicarbonate (HCO_3)		HCO_3	488	÷61	8	HCO_3
9. Chlorides (Cl)		Cl	22,302	÷35.5	628	Cl
10. Sulfates (SO_4)		SO_4	3,750	÷48	78	SO_4
11. Calcium (Ca)		Ca	660	÷20	33	Ca
12. Magnesium (Mg)		Mg	255	÷12.2	21	Mg
13. Total Hardness ($CaCO_3$)			2,700			
14. Total Iron (Fe)			1.8			
15. Barium (Qualitative)			0			
16. Phosphate			25.83			

*Milli equivalents per liter

PROBABLE MINERAL COMPOSITION

*				*
33	Ca	←	HCO_3	8
21	Mg	→	SO_4	78
660	Na	→	Cl	628

Saturation Values Distilled Water 20°C

$CaCO_3$	13 Mg/L
$CaSO_4 \cdot 2H_2O$	2,090 Mg/L
$MgCO_3$	103 Mg/L

Compound	Equiv. Wt.	X Meq/L	= Mg/L
$Ca(HCO_3)_2$	81.04	8	648
$CaSO_4$	68.07	25	1,702
$CaCl_2$	55.50		
$Mg(HCO_3)_2$	73.17		
$MgSO_4$	60.19	21	1,264
$MgCl_2$	47.62		
$NaHCO_3$	84.00		
Na_2SO_4	71.03	32	2,273
NaCl	58.46	628	36,713

REMARKS Produced water
Perfs 4790-4798' (Green River)

Jetco Chemicals, Inc.
A Procter & Gamble Co.

P.O. BOX 1898 CORSICANA, TEXAS 75110
OFFICE: 214/872-3011 PLANT: 214/874-3706 TWX 910/860-5100
U.S... 800/527-2510 (TX.) 800/442-6261

Water Analysis Book

WATER ANALYSIS REPORT

COMPANY ______ ADDRESS ______ DATE: 5-13-87

SOURCE N.D. 1-15 SEC. 15, T9S, R20E DATE SAMPLED ______ ANALYSIS NO. ______

	Analysis		Mg/l (ppm)		*Meq/l	
1. PH	6.4					
2. H_2S (Qualitative)	.5					
3. Specific Gravity	1.048					
4. Dissolved Solids						
5. Suspended Solids						
6. Anaerobic Bacterial Count	C/Ml					
7. Methyl Orange Alkalinity ($CaCO_3$)			360			
8. Bicarbonate (HCO_3)		HCO_3	439	÷61	7	HCO_3
9. Chlorides (Cl)		Cl	40,710	÷35.5	1,147	Cl
10. Sulfates (SO_4)		SO_4	3,600	÷48	75	SO_4
11. Calcium (Ca)		Ca	120	÷20	6	Ca
12. Magnesium (Mg)		Mg	22	÷12.2	2	Mg
13. Total Hardness ($CaCO_3$)			390			
14. Total Iron (Fe)			120			
15. Barium (Qualitative)						
16. Phosphate Residuals						

*Milli equivalents per liter

PROBABLE MINERAL COMPOSITION

Cation	Meq/l	Anion	Meq/l
Ca	6	HCO_3	7
Mg	2	SO_4	75
Na	1,221	Cl	1,147

Compound	Equiv. Wt.	X Meq/l	= Mg/l
$Ca(HCO_3)_2$	81.04	6	486
$CaSO_4$	68.07		
$CaCl_2$	55.50		
$Mg(HCO_3)_2$	73.17	1	73
$MgSO_4$	60.19	1	60
$MgCl_2$	47.62		
$NaHCO_3$	84.00		
Na_2SO_4	71.03	74	5,254
NaCl	58.46	1,147	67,054

Saturation Values	Distilled Water 20°C
$CaCO_3$	13 Mg/l
$CaSO_4 \cdot 2H_2O$	2,090 Mg/l
$MgCO_3$	103 Mg/l

REMARKS Produced water
Perfs 4788-96' (Green River)

SOONER CHEMICALS

SOONER CHEMICAL SPECIALTIES, INC

P. O. Box 711 SEMINOLE, OKLAHOMA 74868 Phone (405) 382-2000

WATER ANALYSIS REPORT

COMPANY Belco Development ADDRESS Vernal, Utah DATE: 8-5-81

SOURCE DC 8-16 Duck Creek Sec. 16, T9S, R20E DATE SAMPLED 8-3-81 ANALYSIS NO. 014

Analysis			Mg/L		*Meq/L	
1. PH	8.4					
2. H_2S (Qualitative)	4.0					
3. Specific Gravity	1.020					
4. Dissolved Solids						
5. Suspended Solids						
6. Phenolphthalein Alkalinity ($CaCO_3$)						
7. Methyl Orange Alkalinity ($CaCO_3$)			500			
8. Bicarbonate (HCO_3)		HCO_3	610	÷61	10	HCO_3
9. Chlorides (Cl)		Cl	16,992	÷35.5	479	Cl
10. Sulfates (SO_4)		SO_4	4,500	÷48	94	SO_4
11. Calcium (Ca)		Ca	120	÷20	6	Ca
12. Magnesium (Mg)		Mg	72	÷12.2	6	Mg
13. Total Hardness ($CaCO_3$)			600			
14. Total Iron (Fe)			0.1			
15. Barium (Qualitative)			0			
16. Phosphate			3.35			

*Milli equivalents per liter

PROBABLE MINERAL COMPOSITION

*			*
6	Ca	HCO_3	10
6	Mg	SO_4	94
571	Na	Cl	479

Compound	Equiv. Wt.	X Meq/L	= Mg/L
$Ca(HCO_3)_2$	81.04	6	486
$CaSO_4$	68.07		
$CaCl_2$	55.50		
$Mg(HCO_3)_2$	73.17	4	293
$MgSO_4$	60.19	2	120
$MgCl_2$	47.62		
$NaHCO_3$	84.00		
Na_2SO_4	71.03	92	6,535
NaCl	58.46	479	28,002

Saturation Values	Distilled Water 20°C
$CaCO_3$	13 Mg/L
$CaSO_4 \cdot 2H_2O$	2,090 Mg/L
$MgCO_3$	103 Mg/L

REMARKS Produced water
Perfs 4869-5006' (Green River)

Go WIRELINE SERVICES
GEARHART-OWEN

Gamma-Ray Bond Log

FILING NO

COMPANY BELCO PETROLEUM INC.
WELL NATURAL BUTTES #21-20B
FIELD NATURAL BUTTES
COUNTY UINTAH STATE UTAH
LOCATION 1037 FNL 1033 FEL
43-047-30359
SEC 20 TWP 9S RGE 20E

OTHER SERVICES:

PERMANENT DATUM GL ELEV. 4769
LOG MEASURED FROM KB 16 FT ABOVE PERM. DATUM
DRILLING MEASURED FROM KB

ELEV. K.B. 4785
D.F.
G.L. 4769

Date	3-23-78		
Run No.	ONE		
Type Log	G/R CBL		
Depth-Driller			
Depth-Logger	6982		
Bottom logged interval	6976		
Top logged interval	1145		
Type fluid in hole	KCL WATER		
Max rec. temp., deg F.			
Operating rig time	6 HOURS		
Recorded by	MCCLAY		
Witnessed by	MR. HARMON		

Run No.	Bit	Bore Hole Record From	To	Casing Record Size	Wgt.	From	To
				9 5/8	36#	0	196
				4 1/2	11.6#	0	7025

COMPRESSIVE STRENGTH (p.s.i. Curing Temp.)								
e Elapsed	Surface		Protective		Production		Liner	
24 hrs.		°F		°F		°F		°F
48 hrs.		°F		°F		°F		°F
72 hrs.		°F		°F		°F		°F

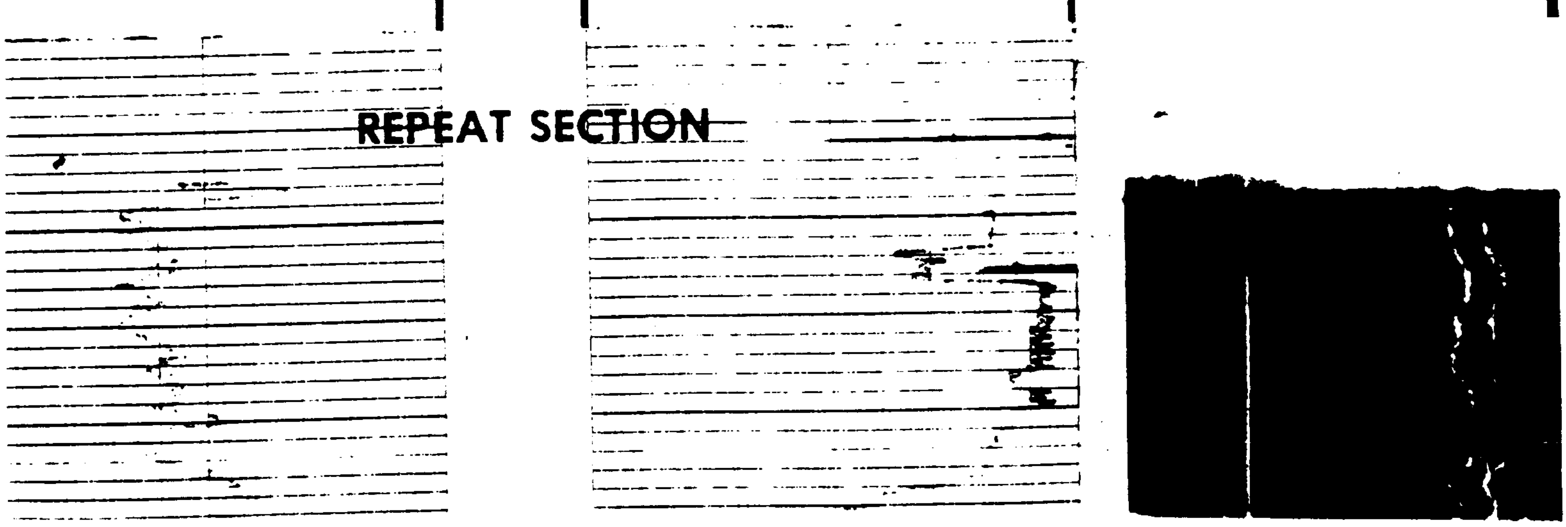
PRIMARY CEMENTING PROCEDURE	Hour — date	Hours from start of operation
rted pumping cement		
g on bottom		
ease pressure		
rt Cement Bond Log		
sh Cement Bond Log		

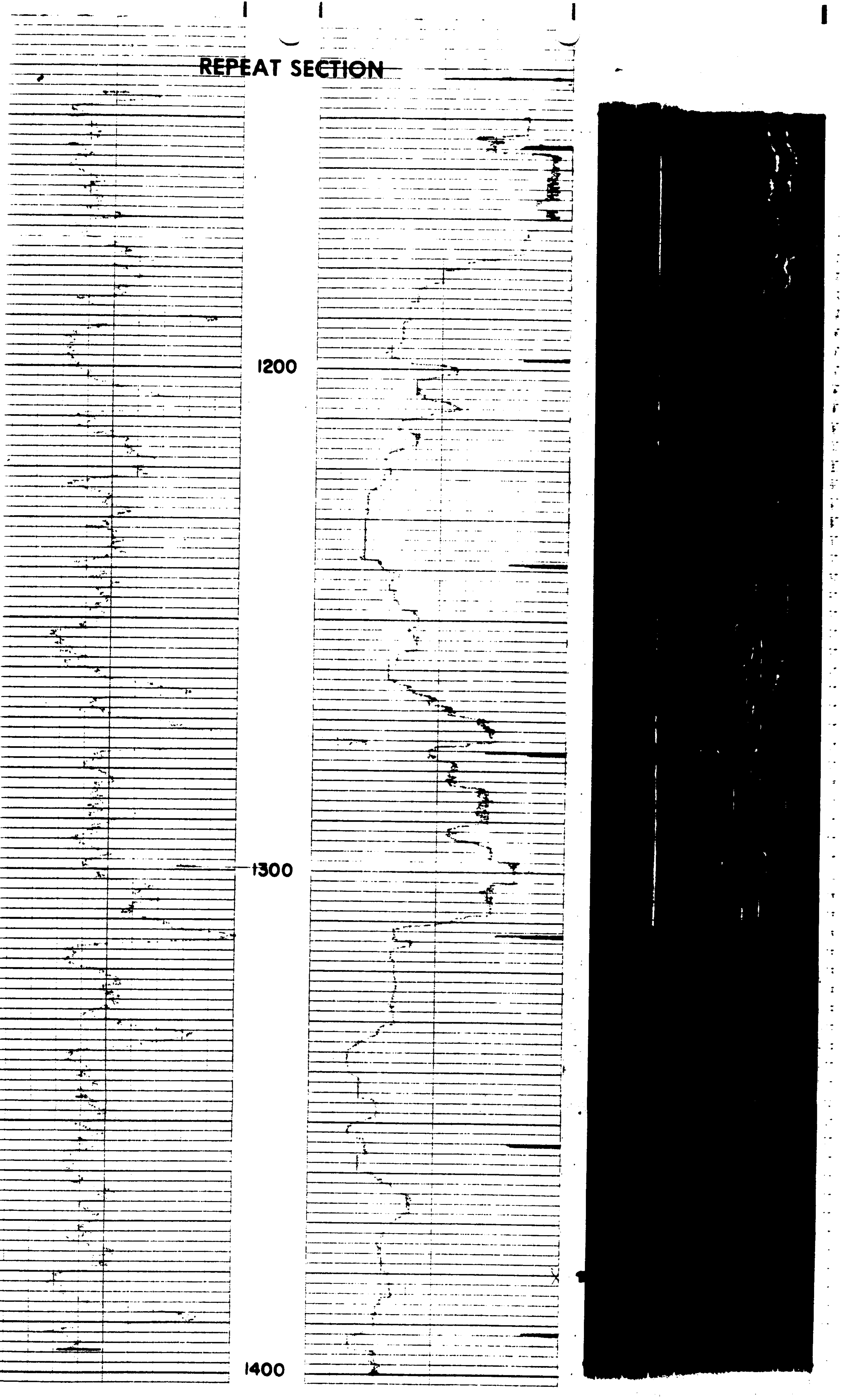
Equipment Data
Type standoff
Logging speed
Bias: Max.
Cartridge No.
Spacing

ceding fluid ____ Volume ____ bbls.
urns: Full ____ Partial ____ None ____

Pipe reciprocated during Pumping: Yes ____ No ____
Pipe reciprocated after plug down: Yes ____ min., No ____

GAMMA RAY	DEPTHS	BOND LOG millivolts	SEISMIC SPECTRUM
	5" = 100'	BONDING INCREASES 0 50	CASING COLLARS

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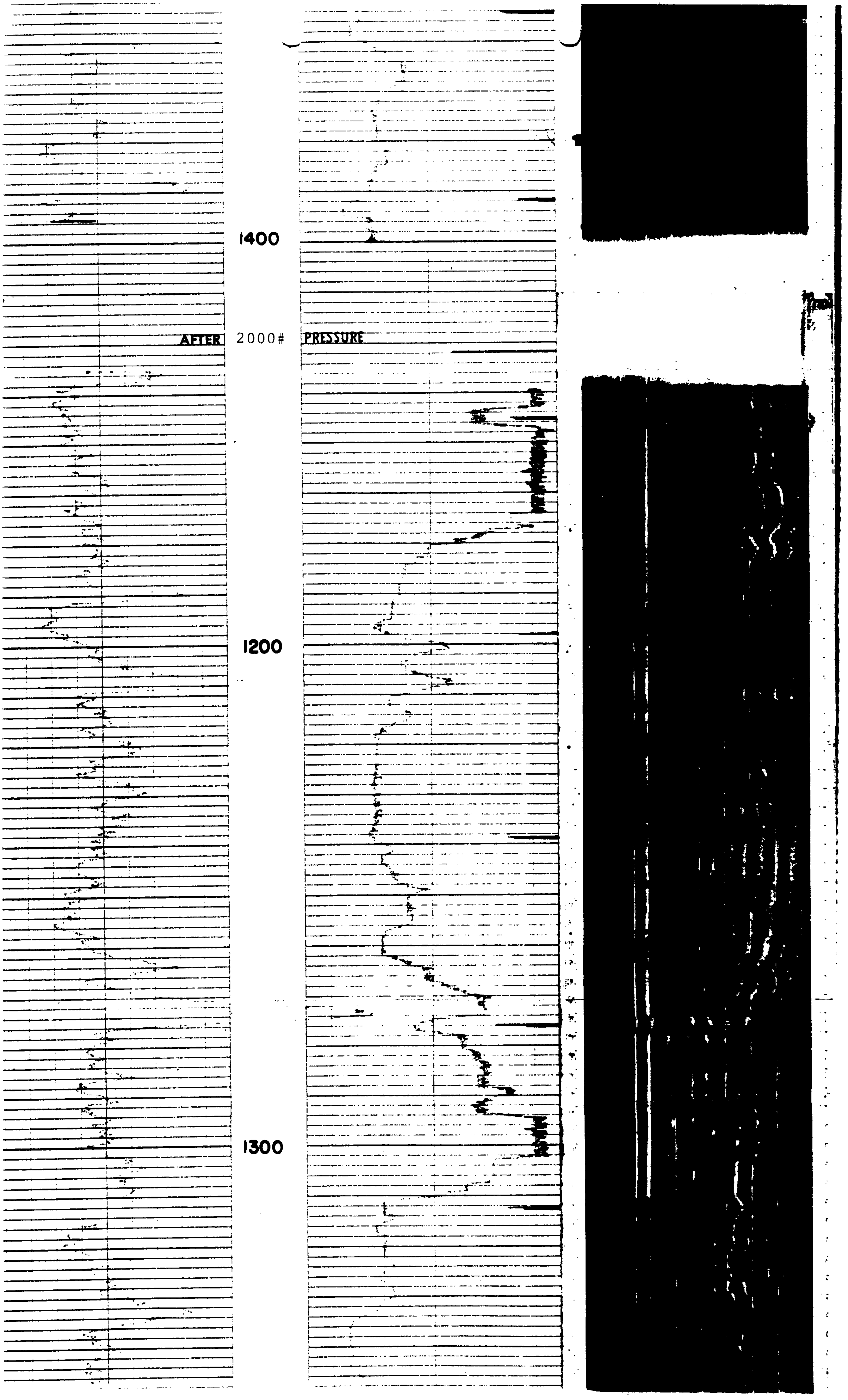
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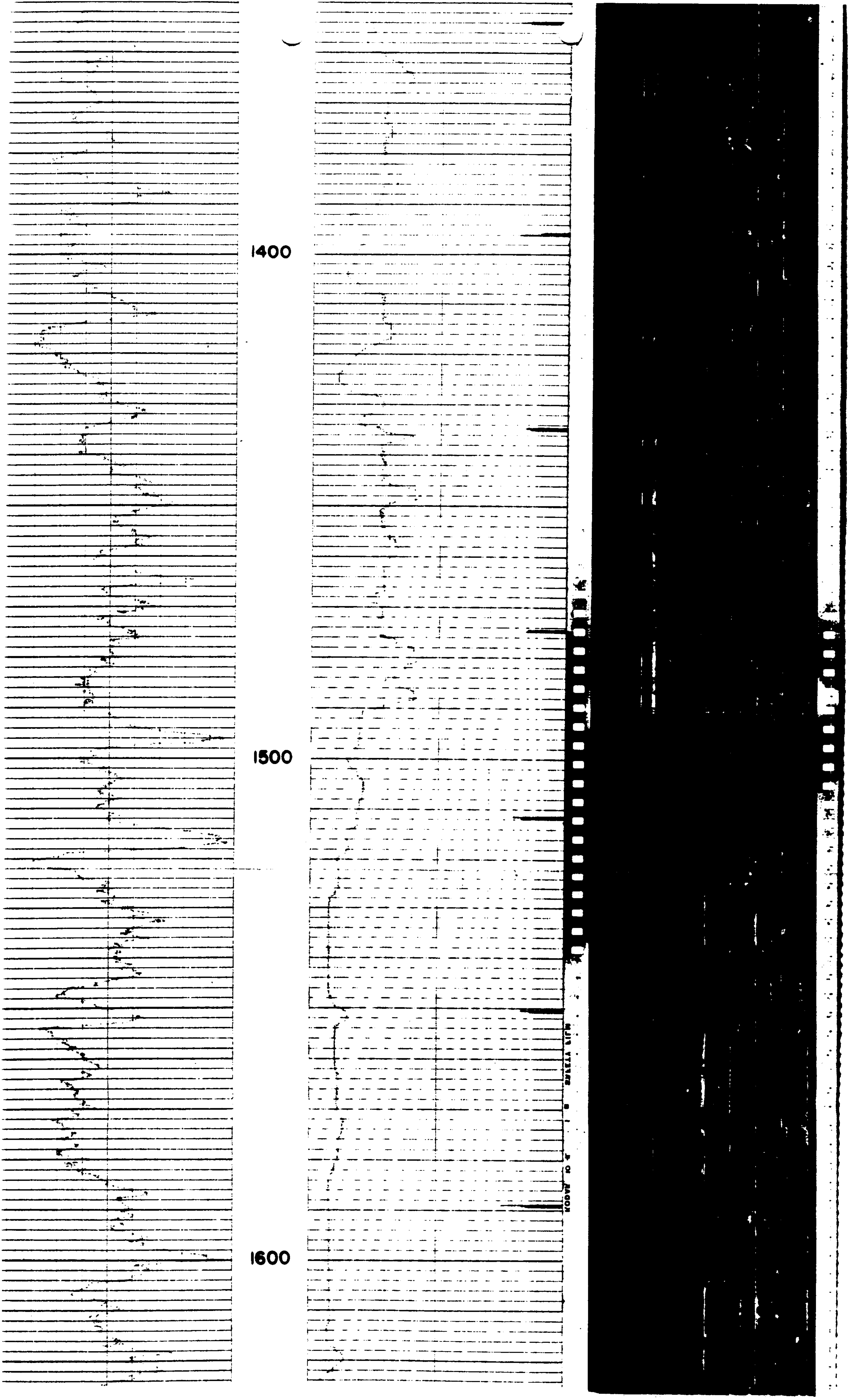
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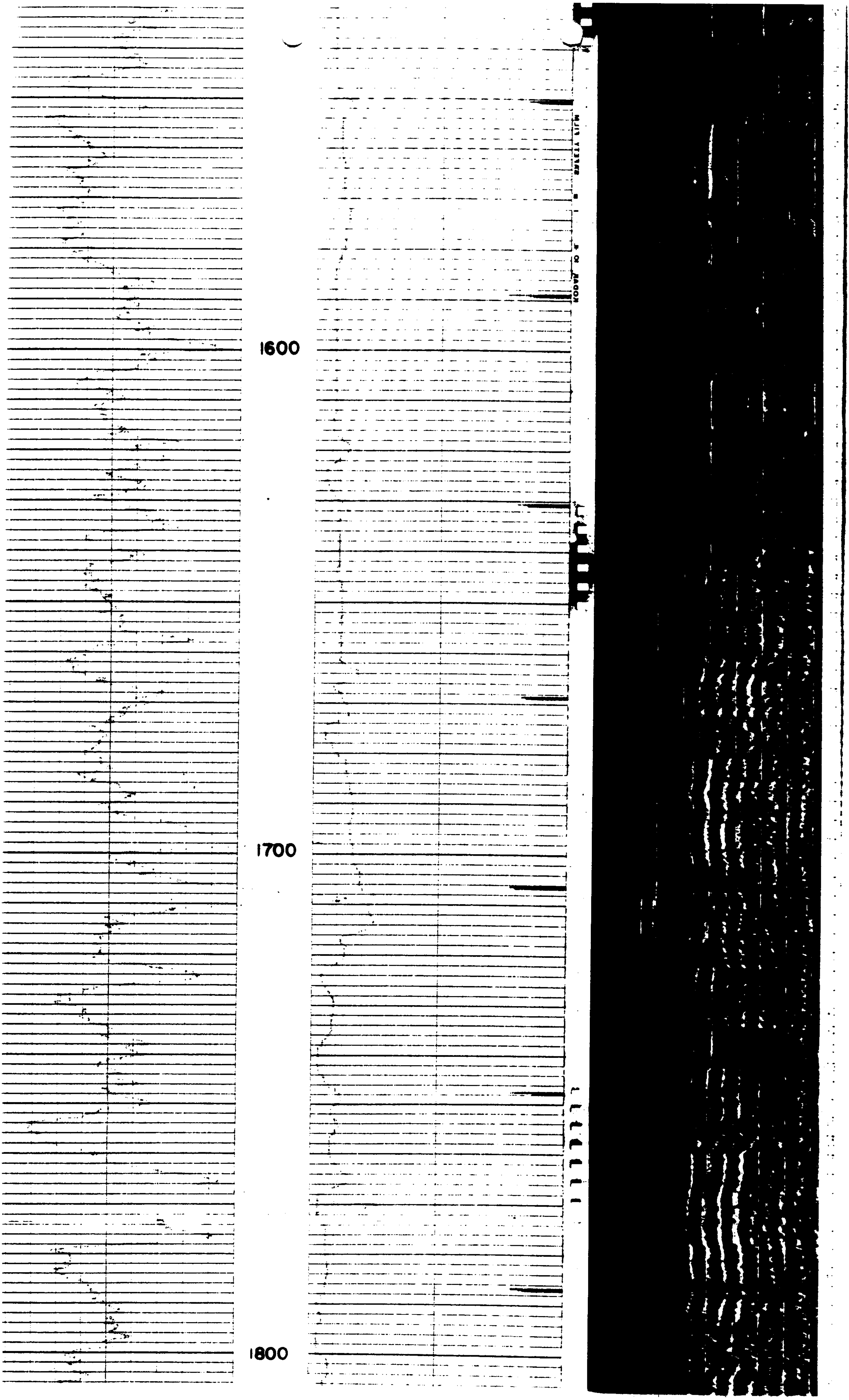
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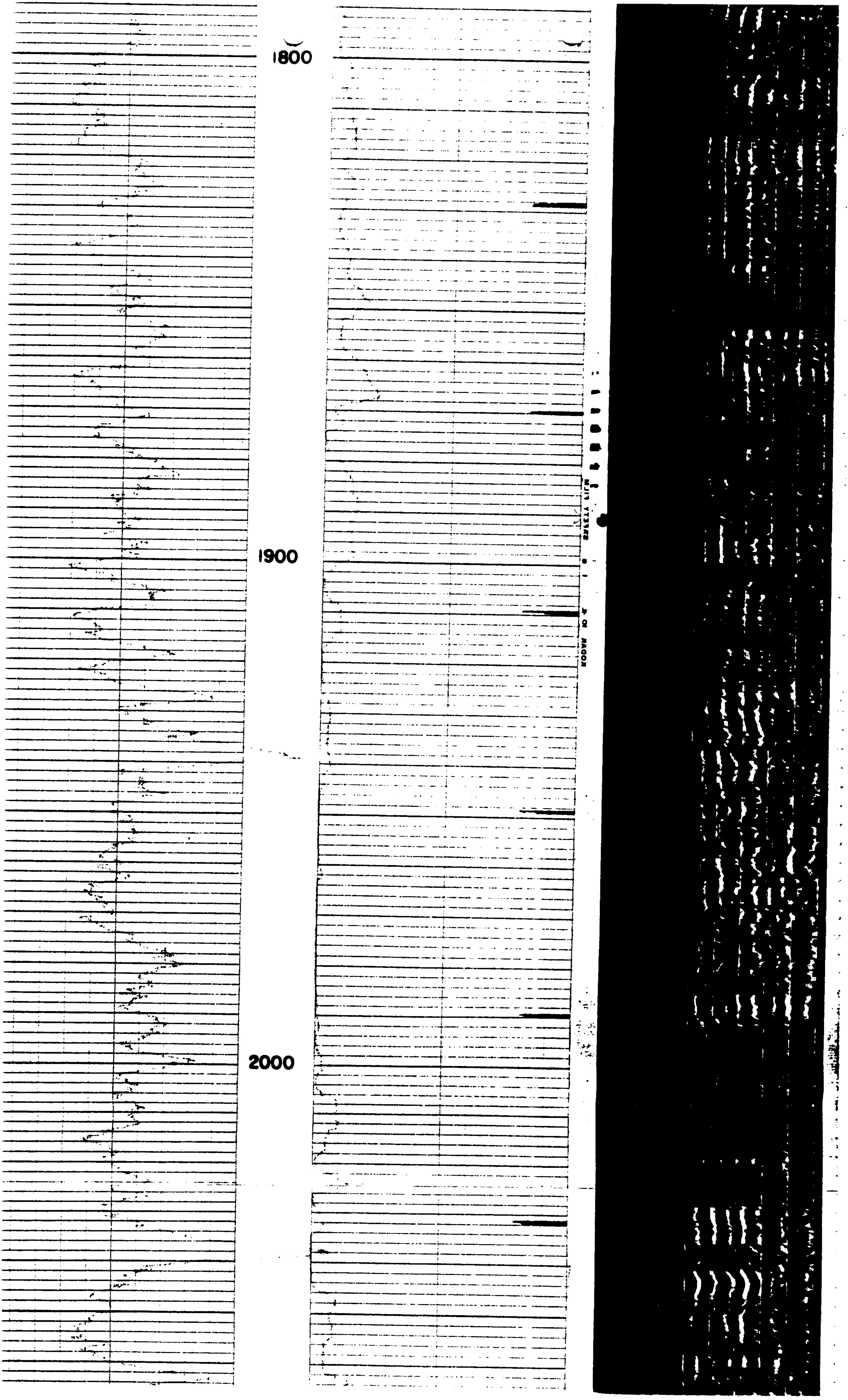
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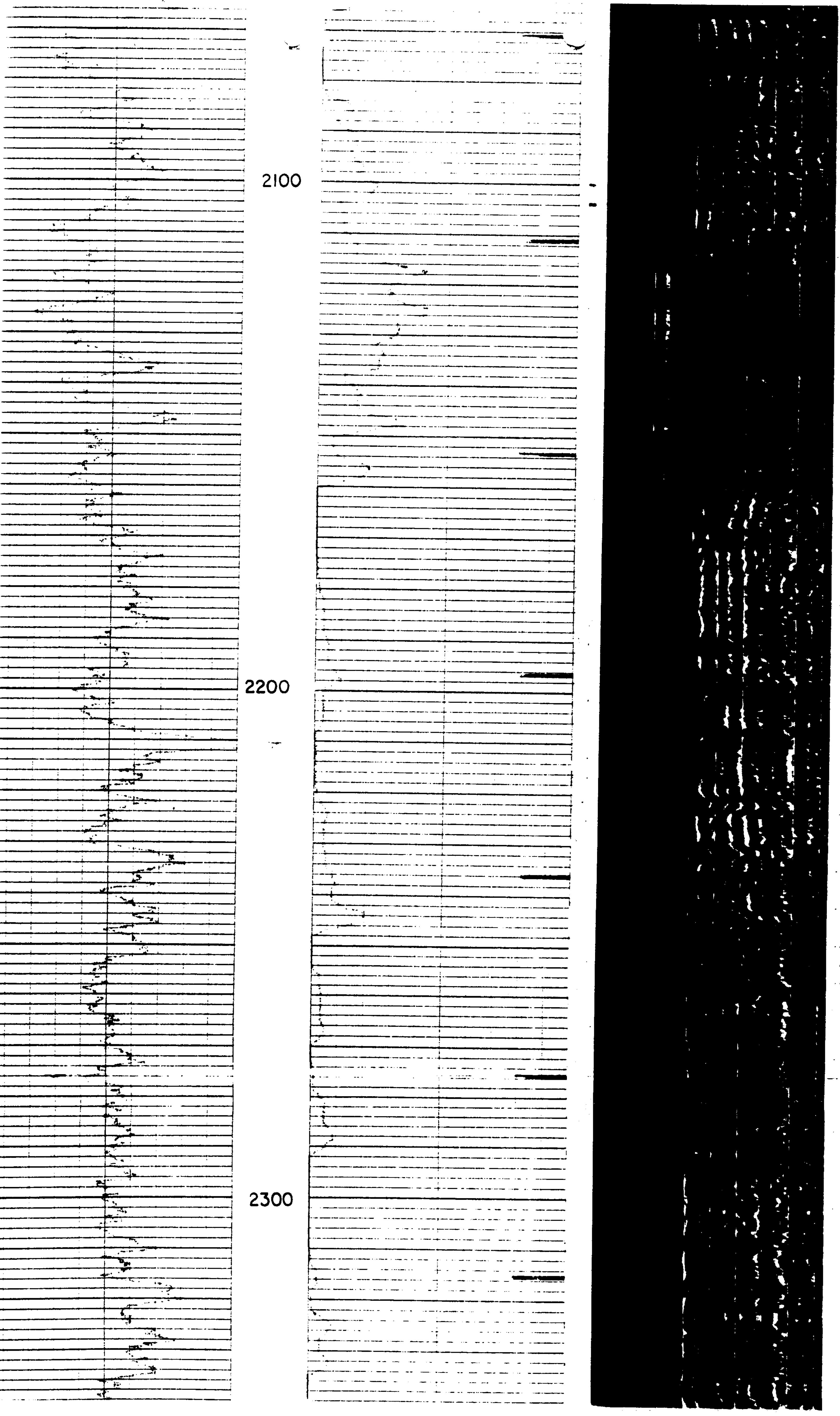
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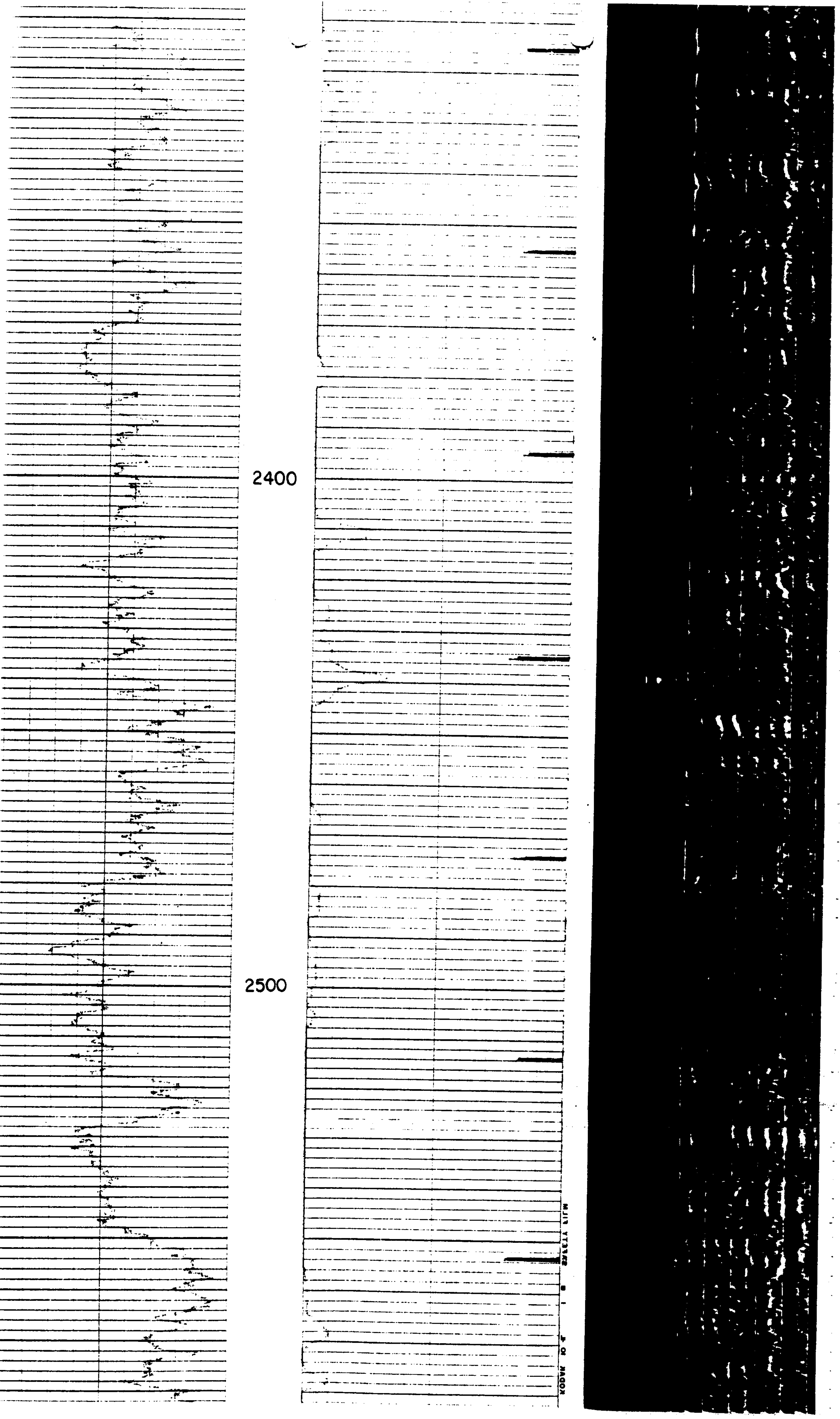
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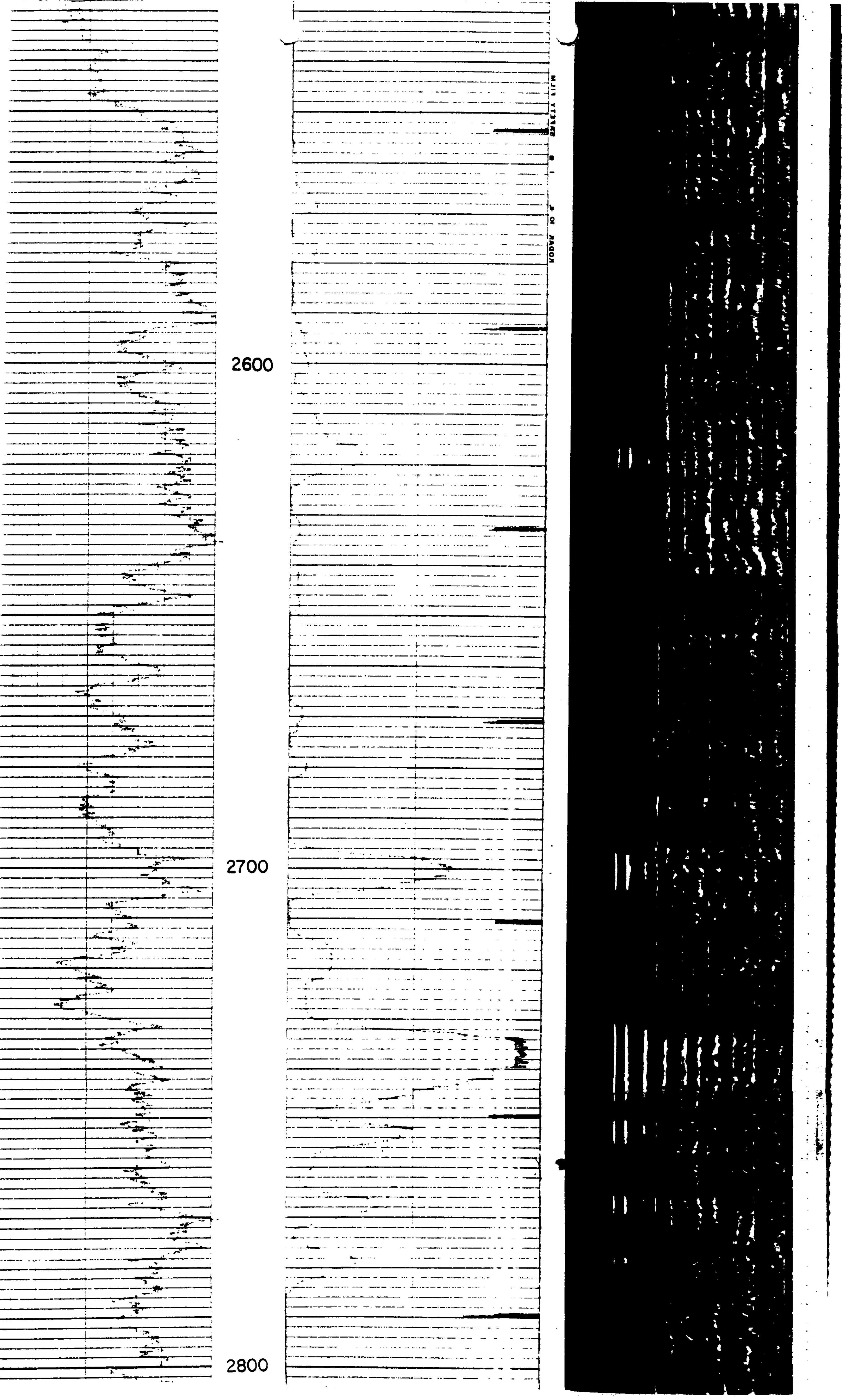
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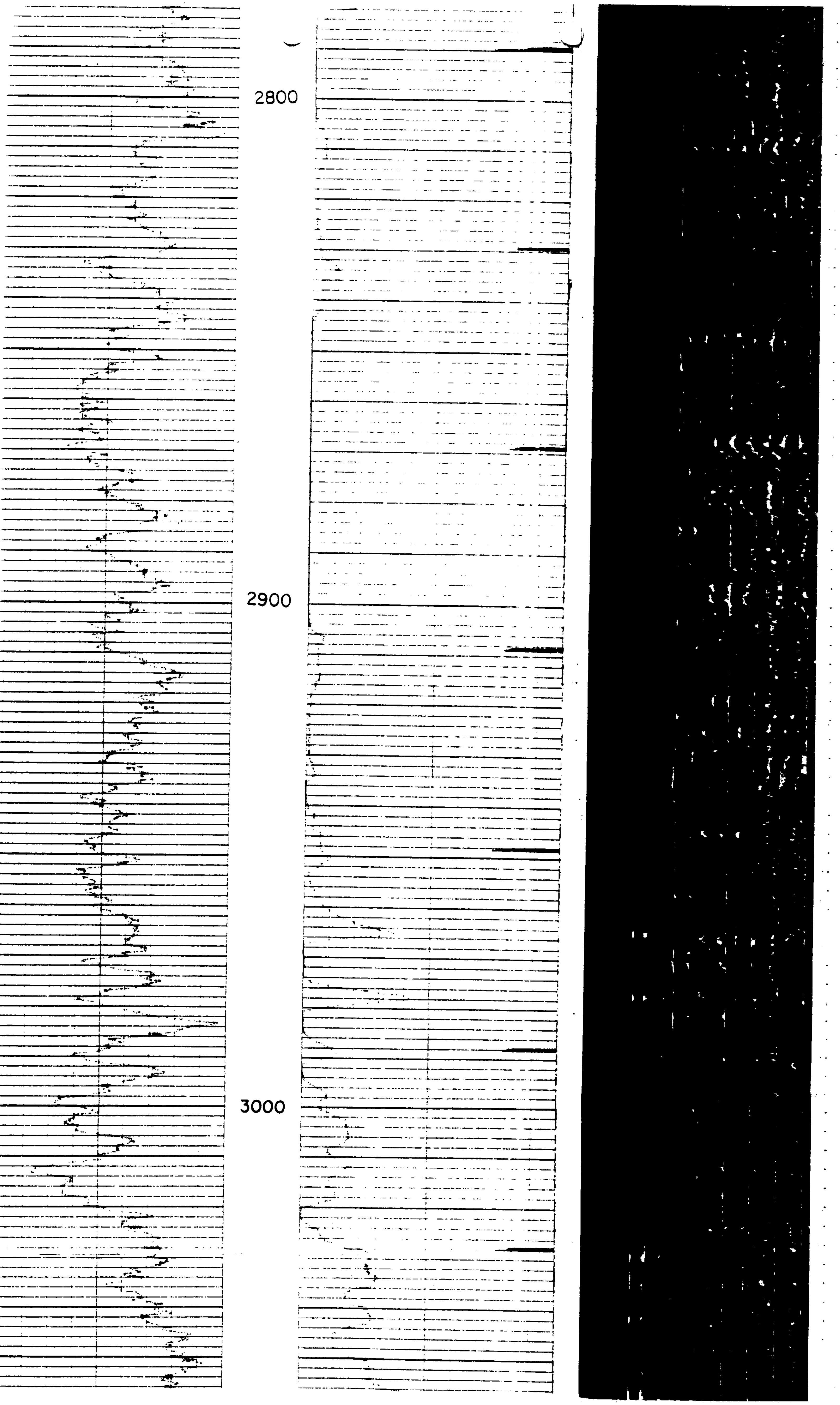
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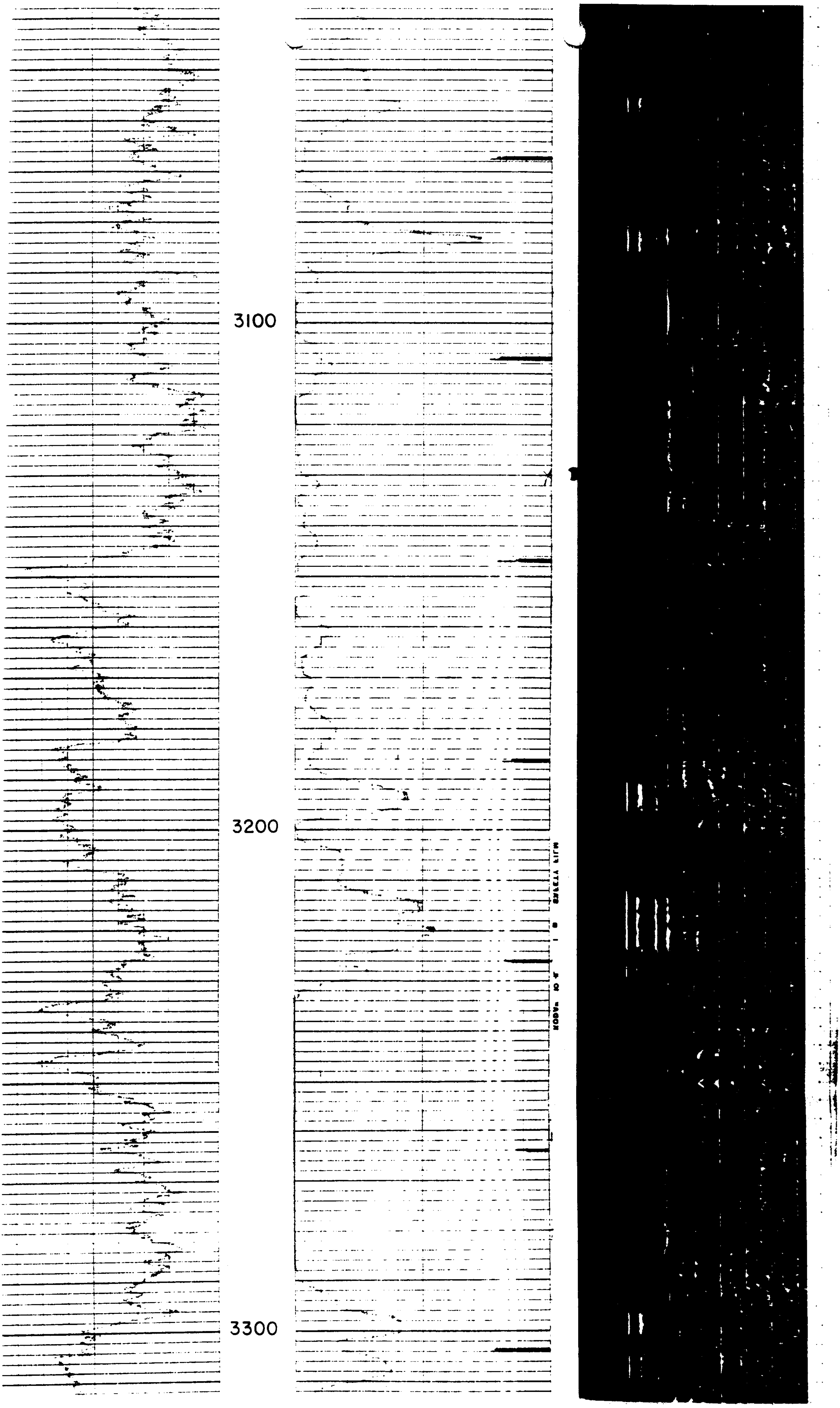
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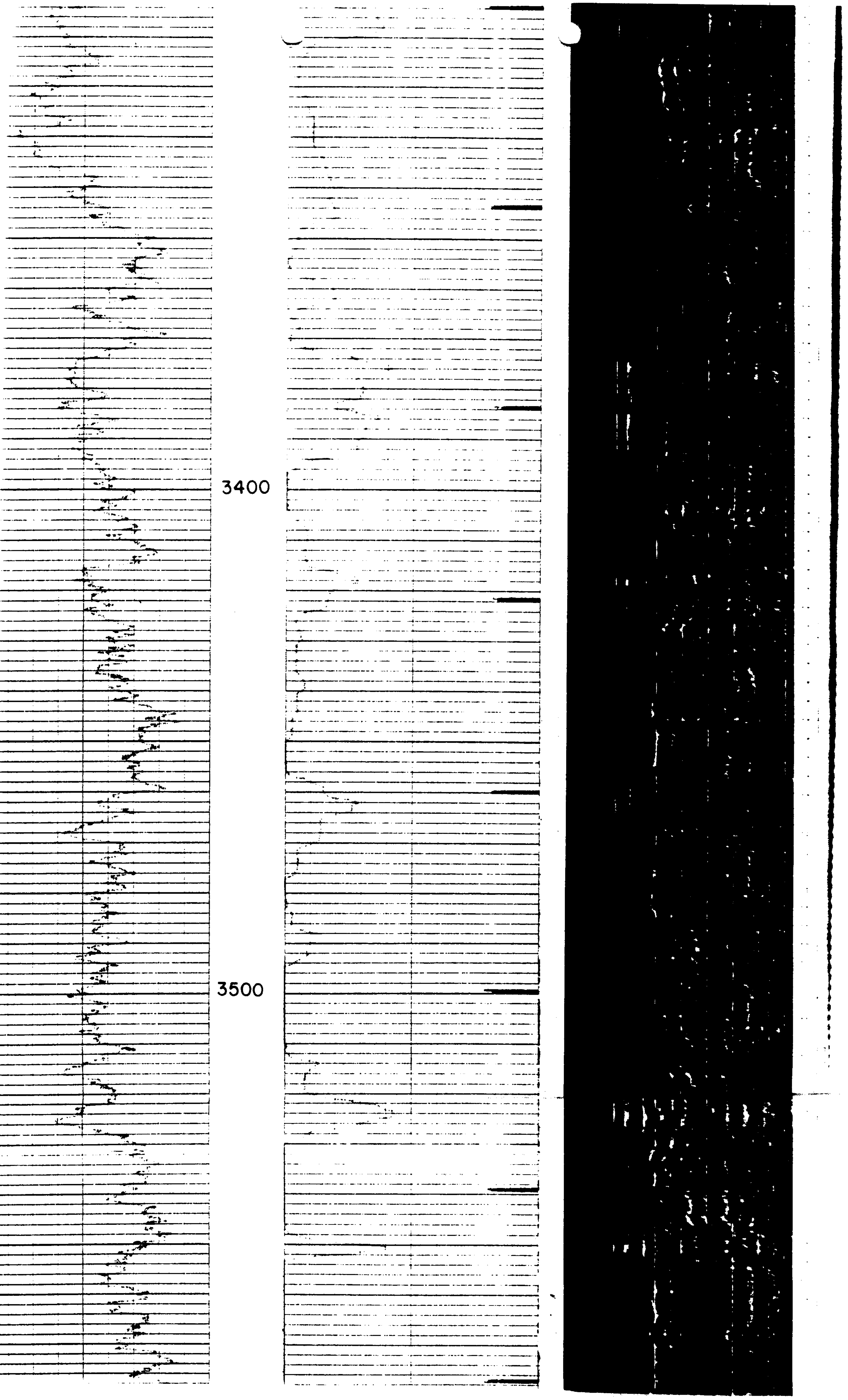
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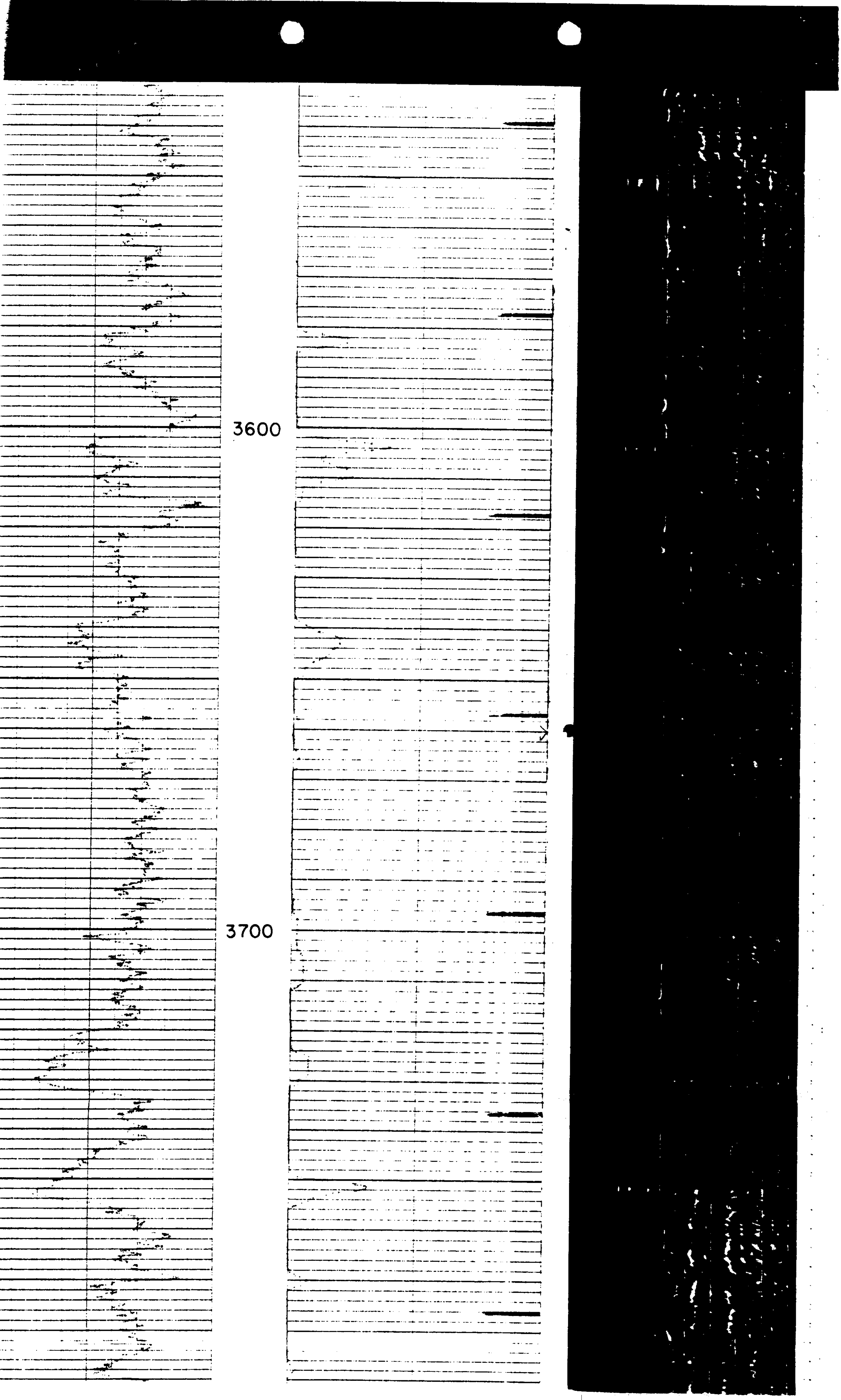
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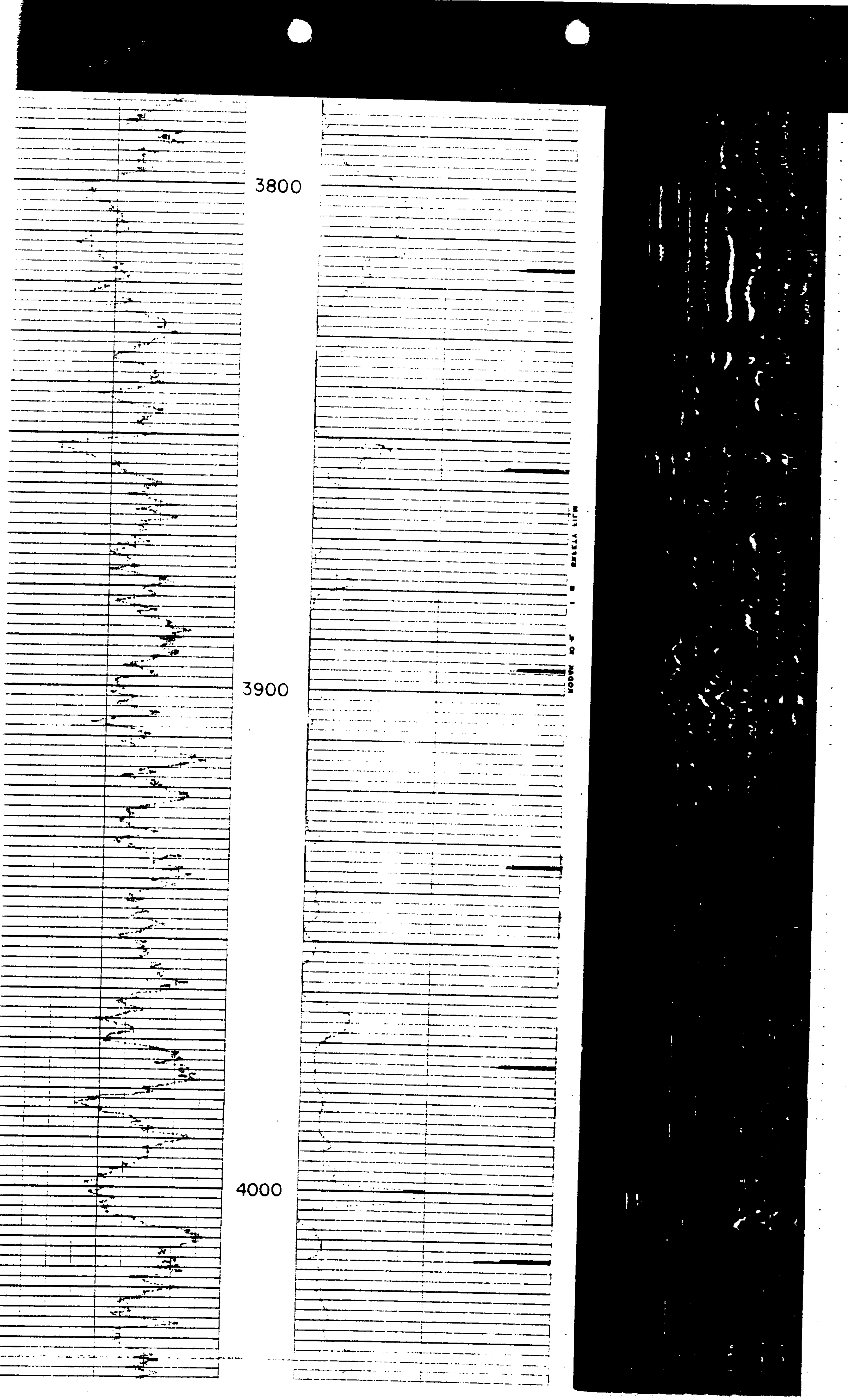
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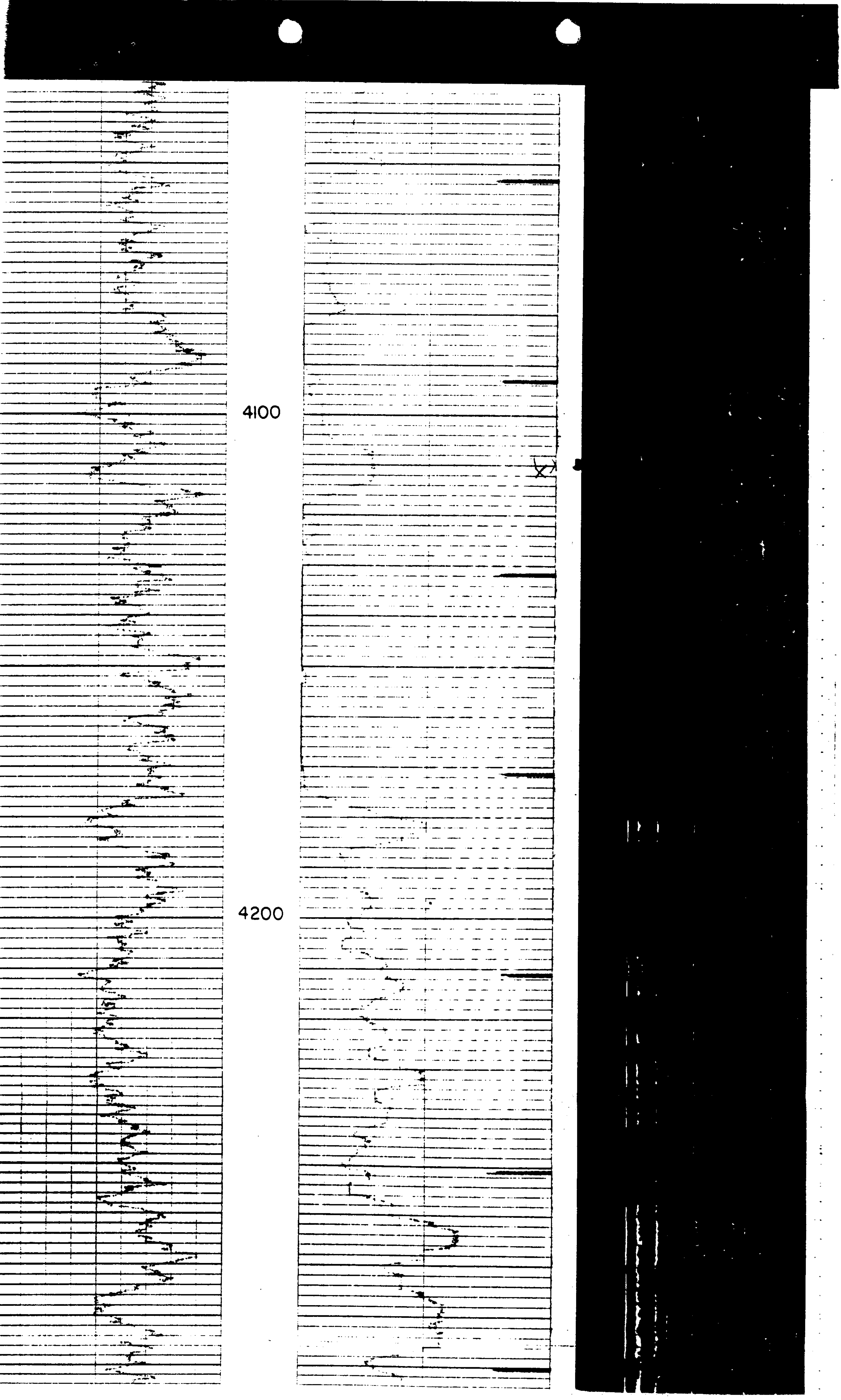
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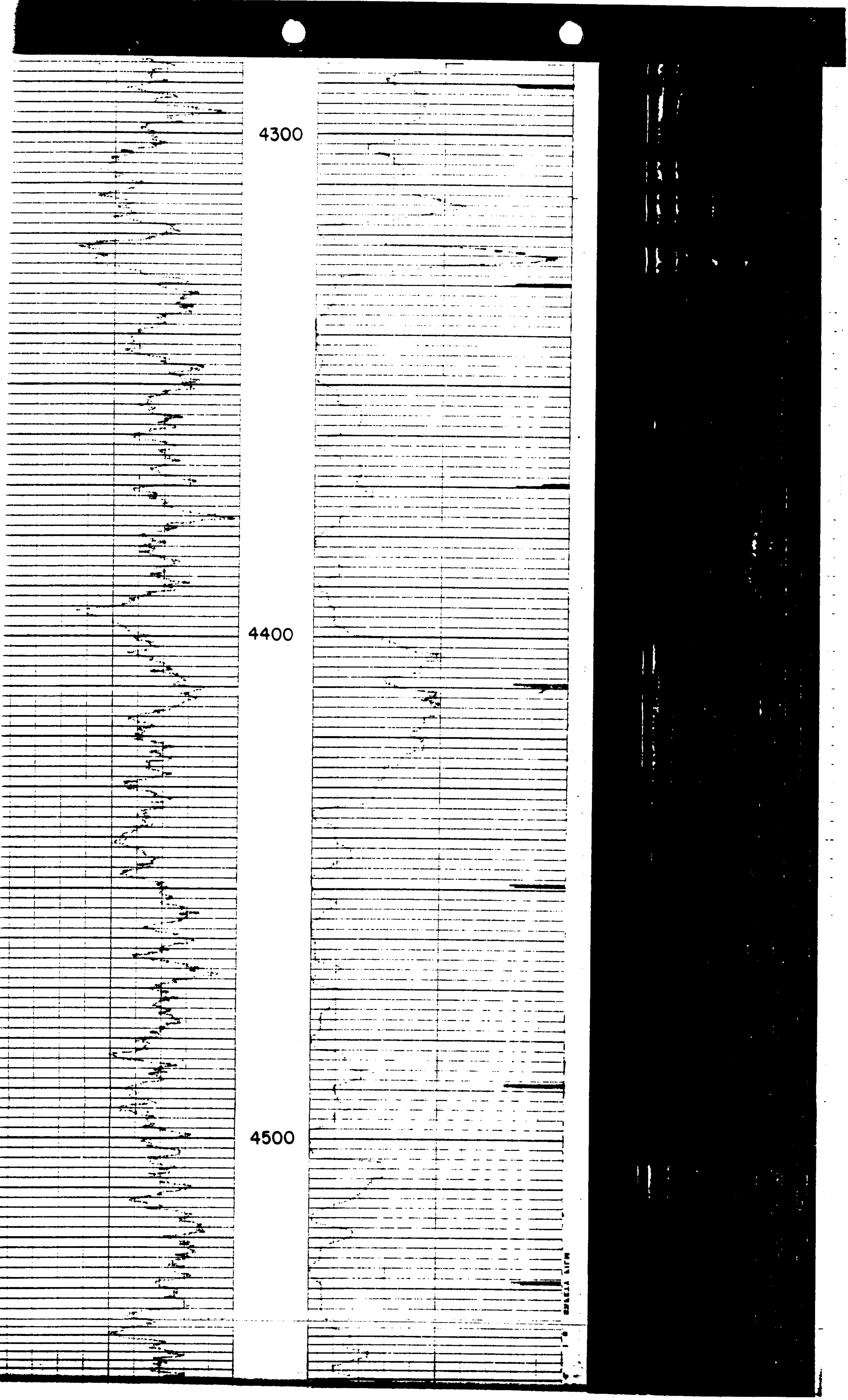
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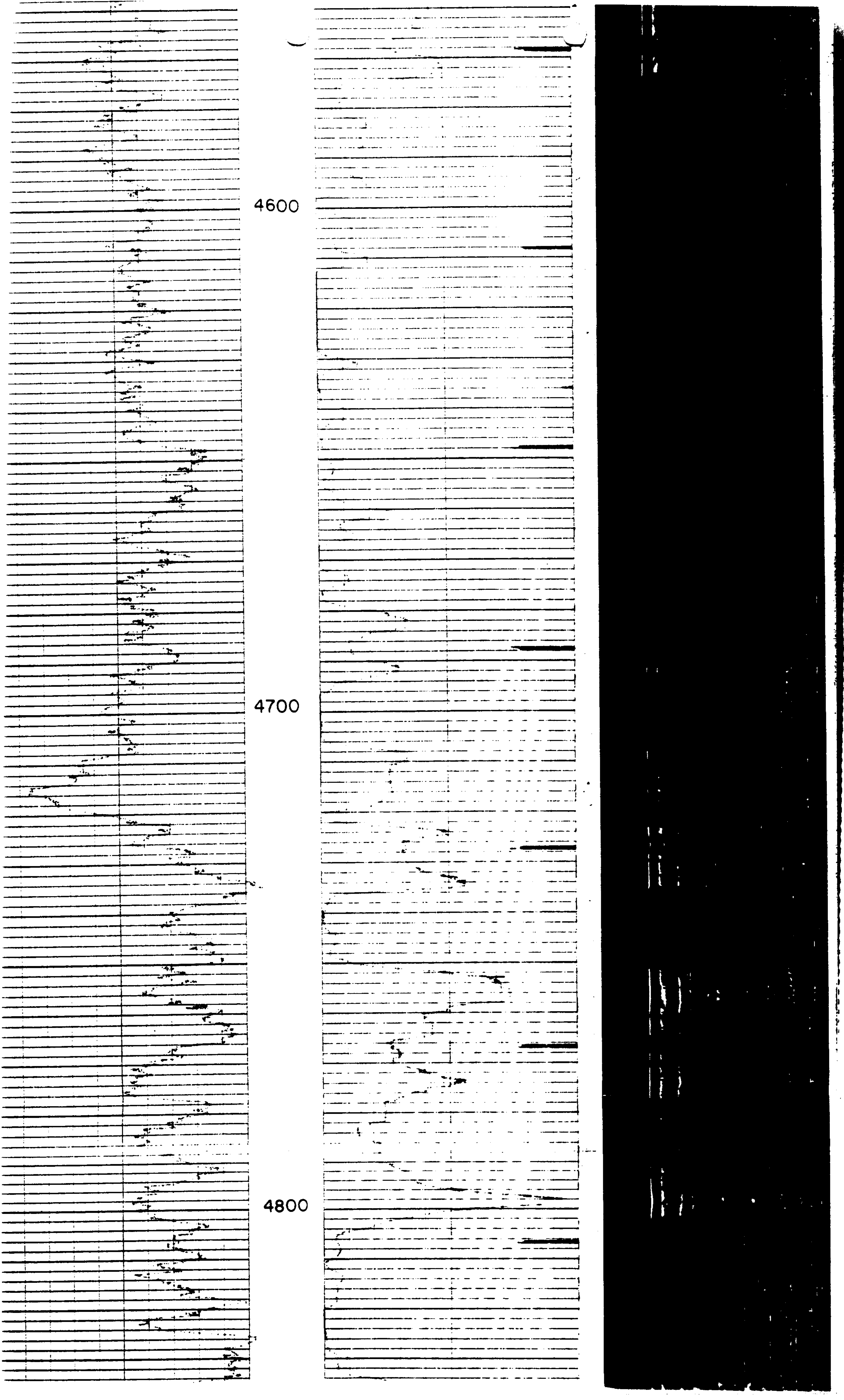
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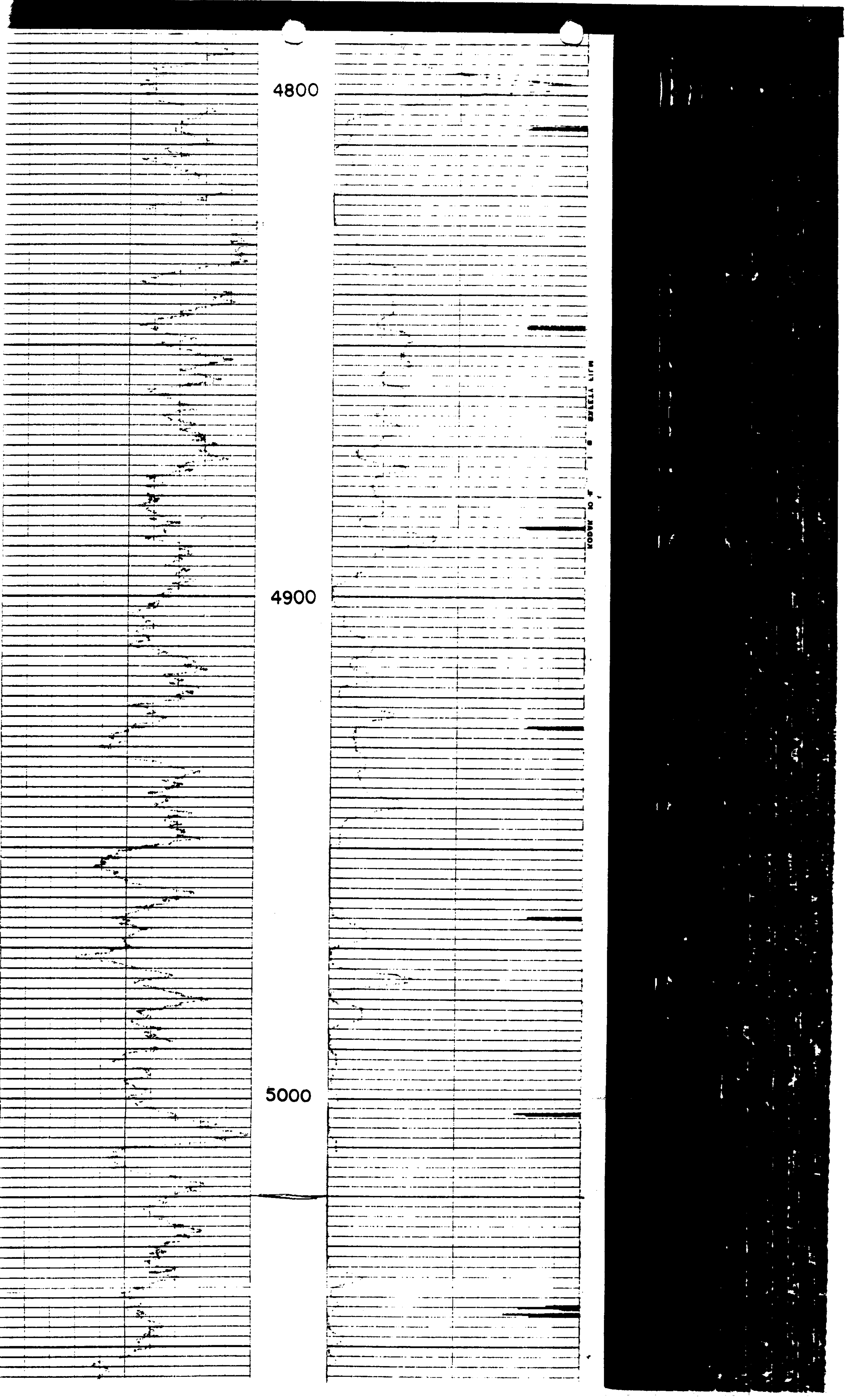
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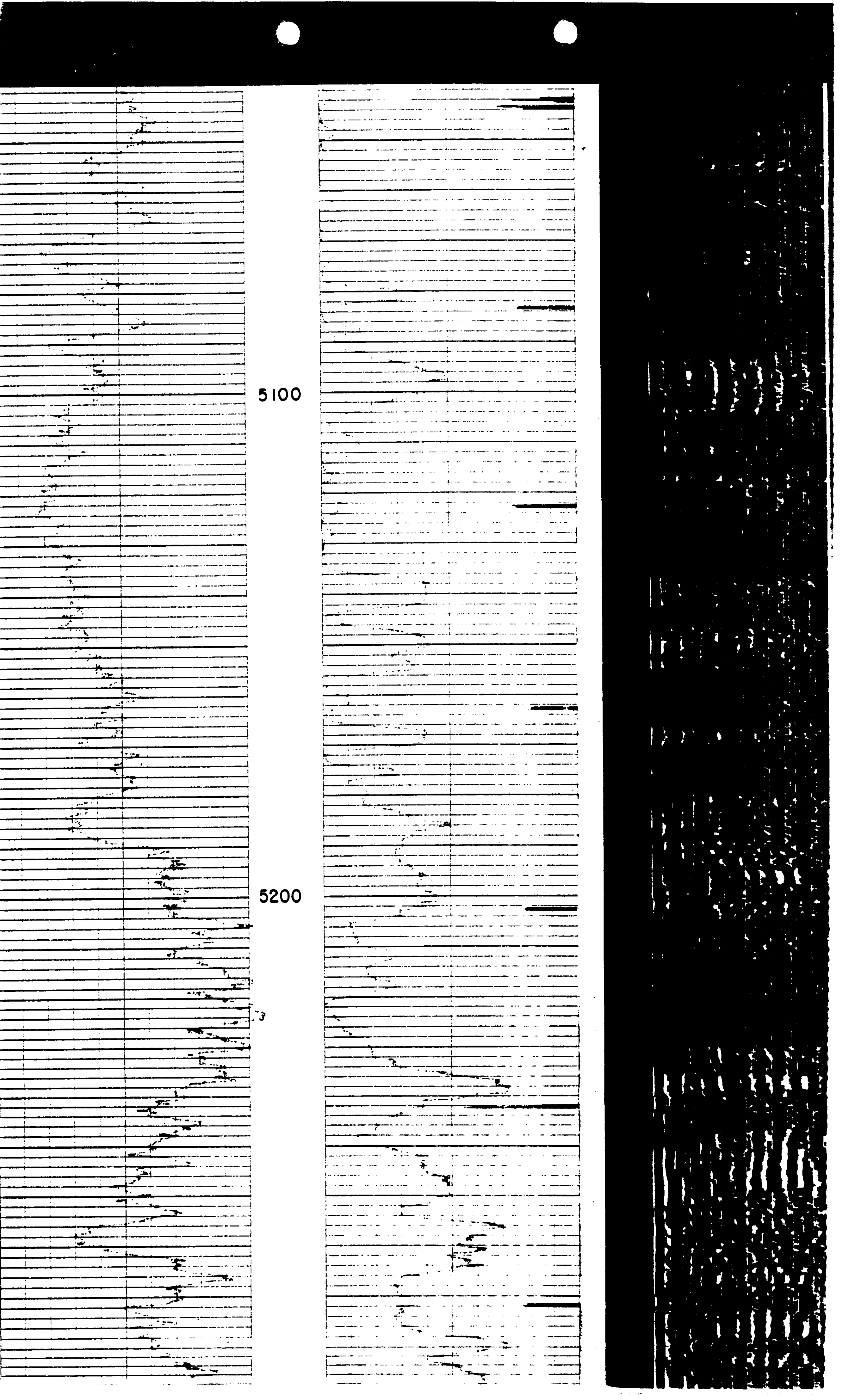
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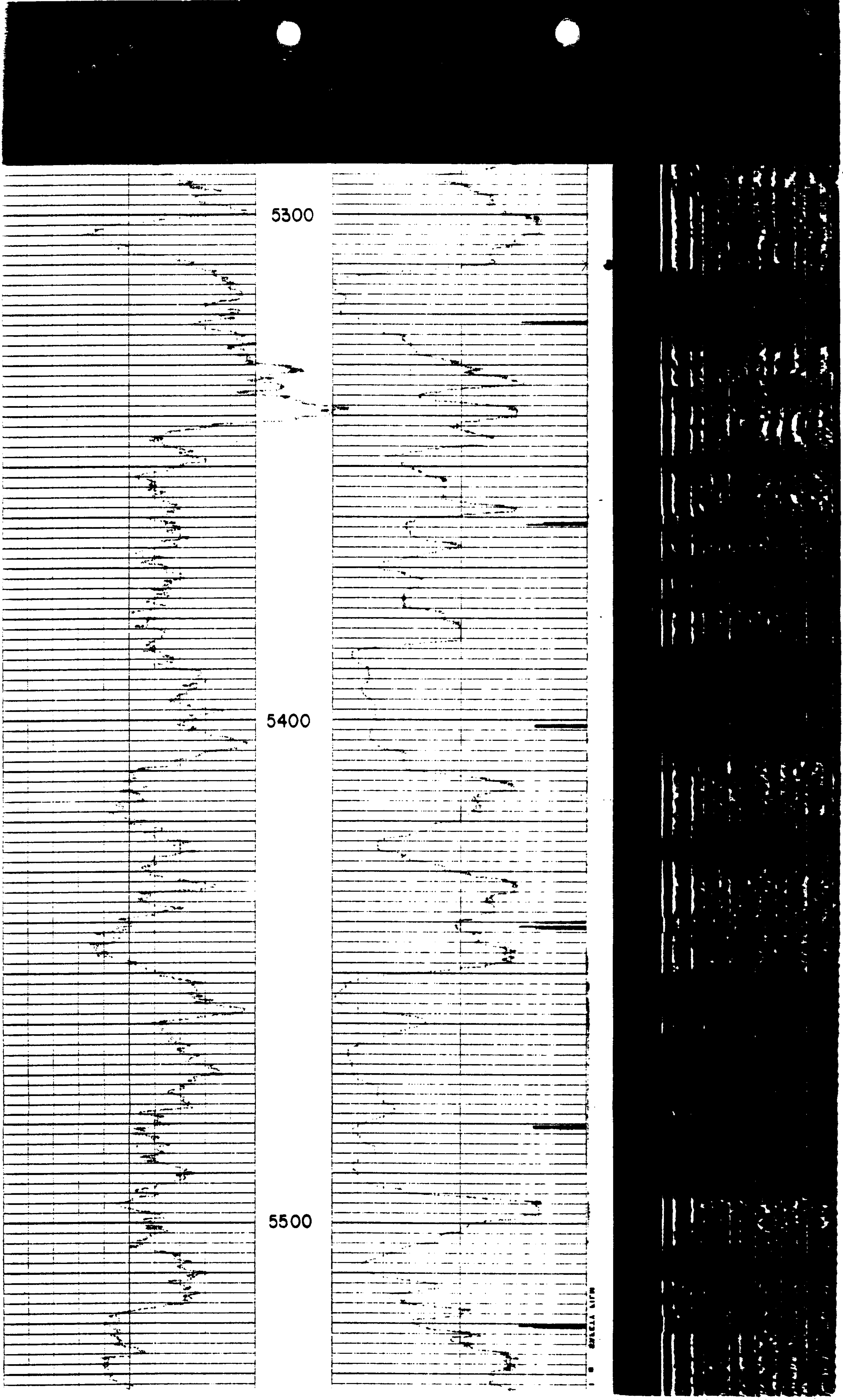
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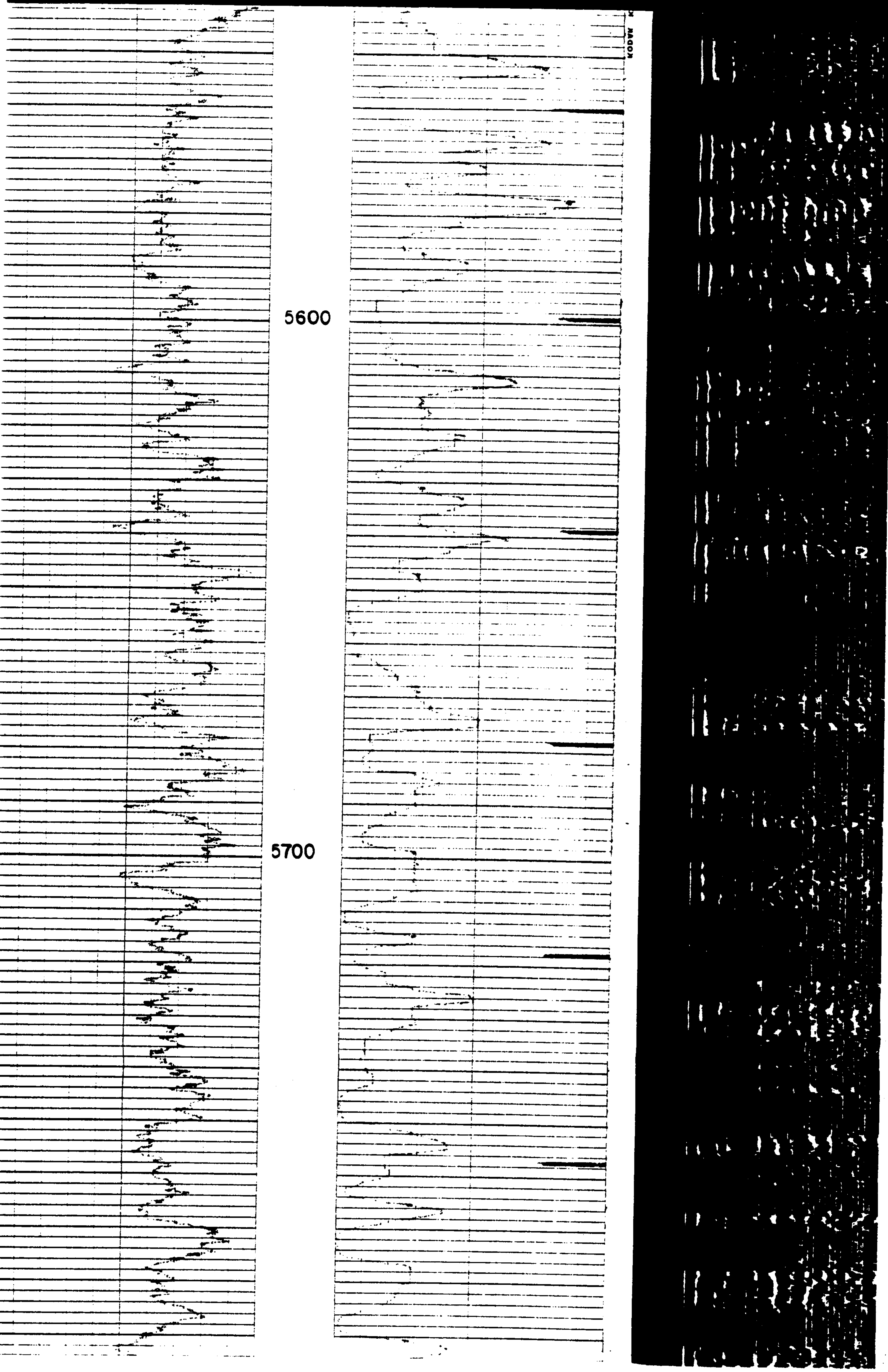

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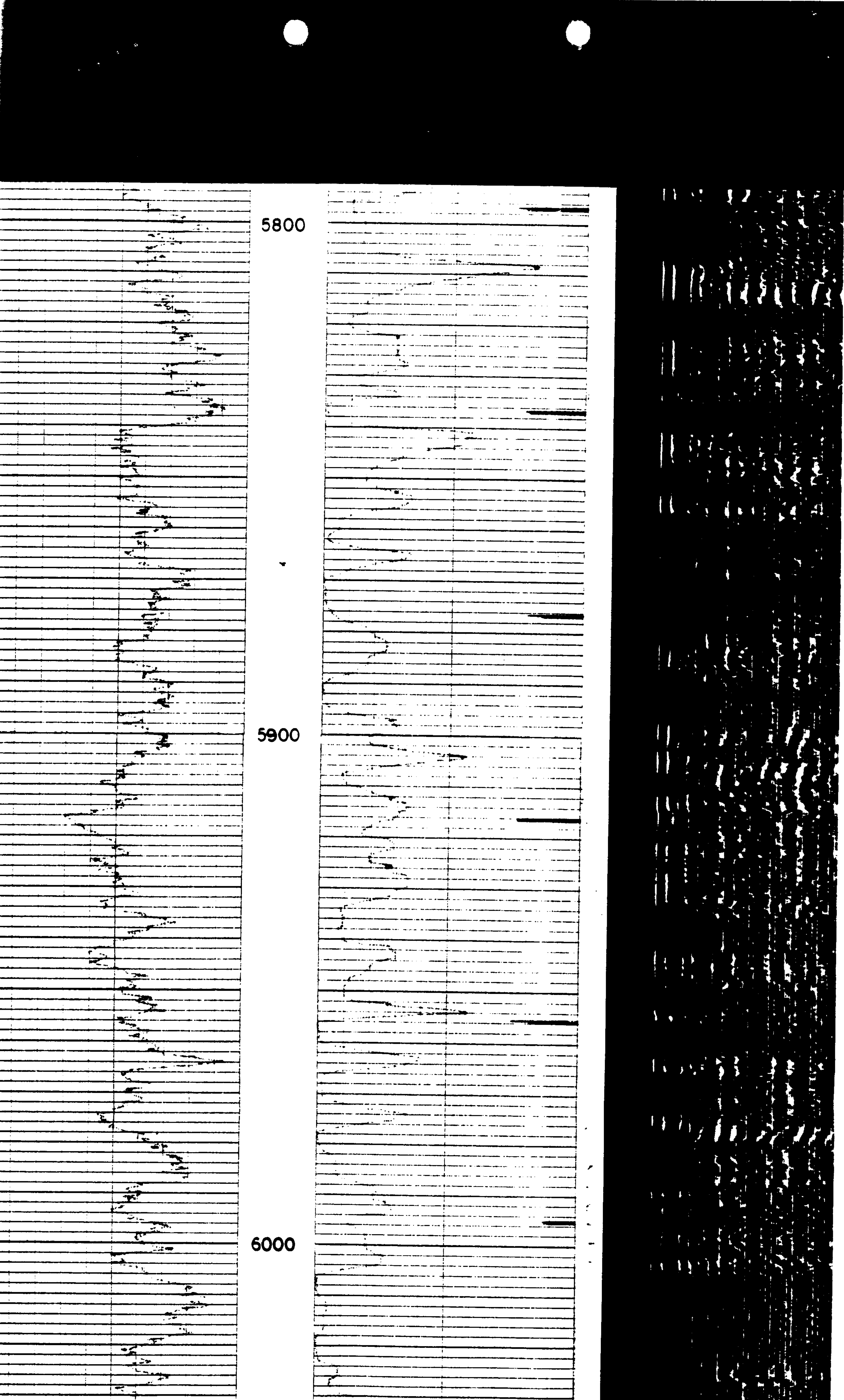
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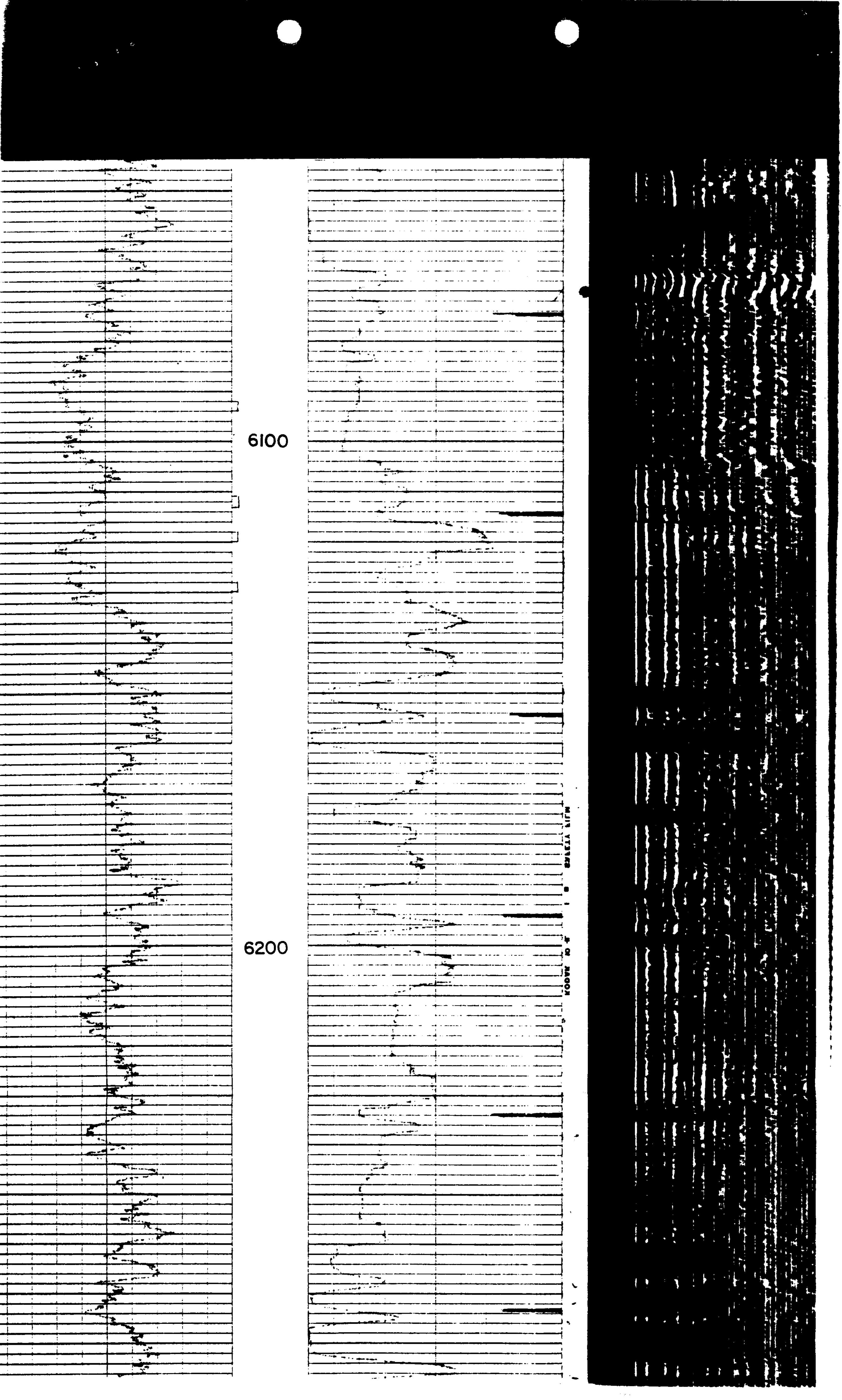
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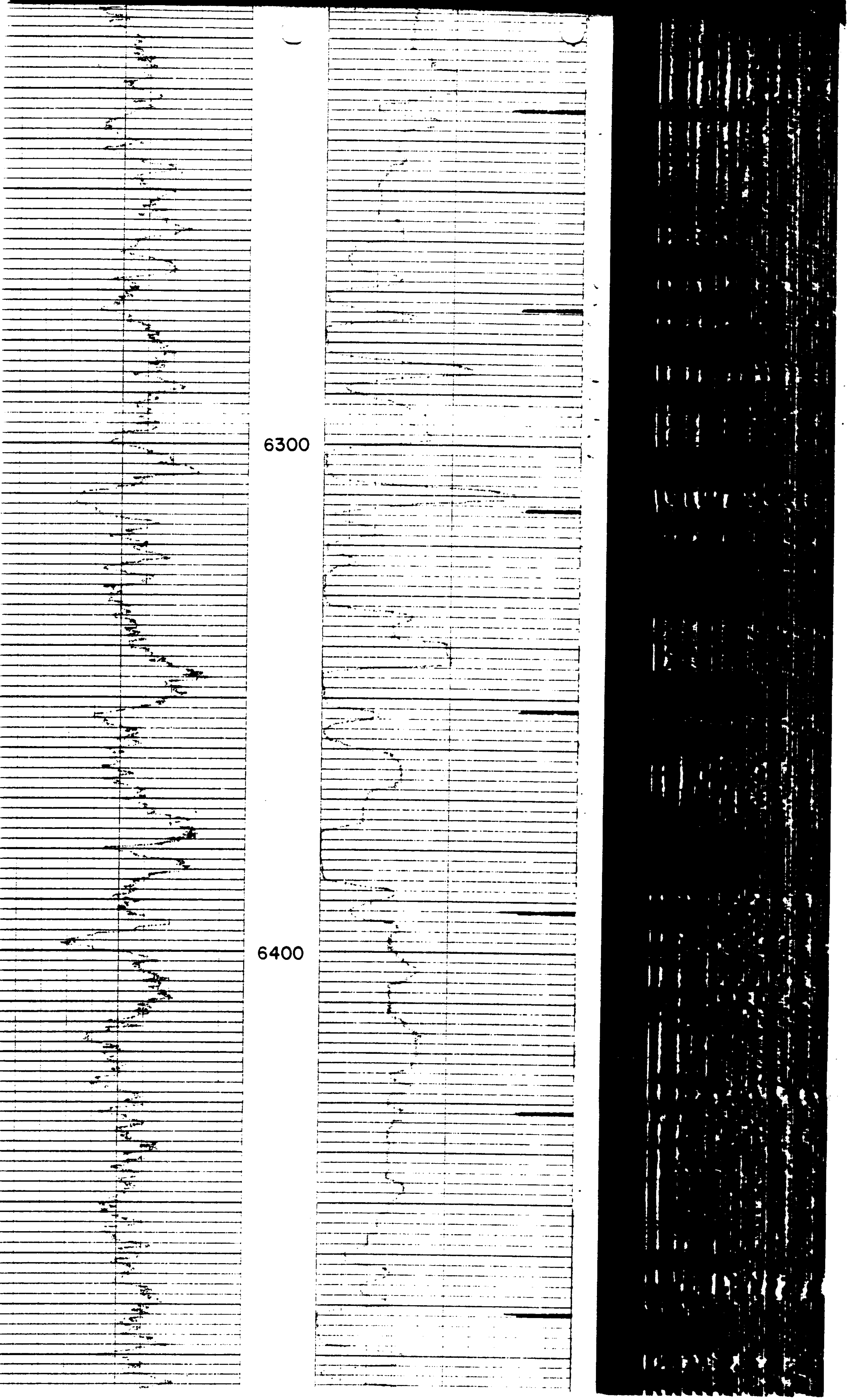
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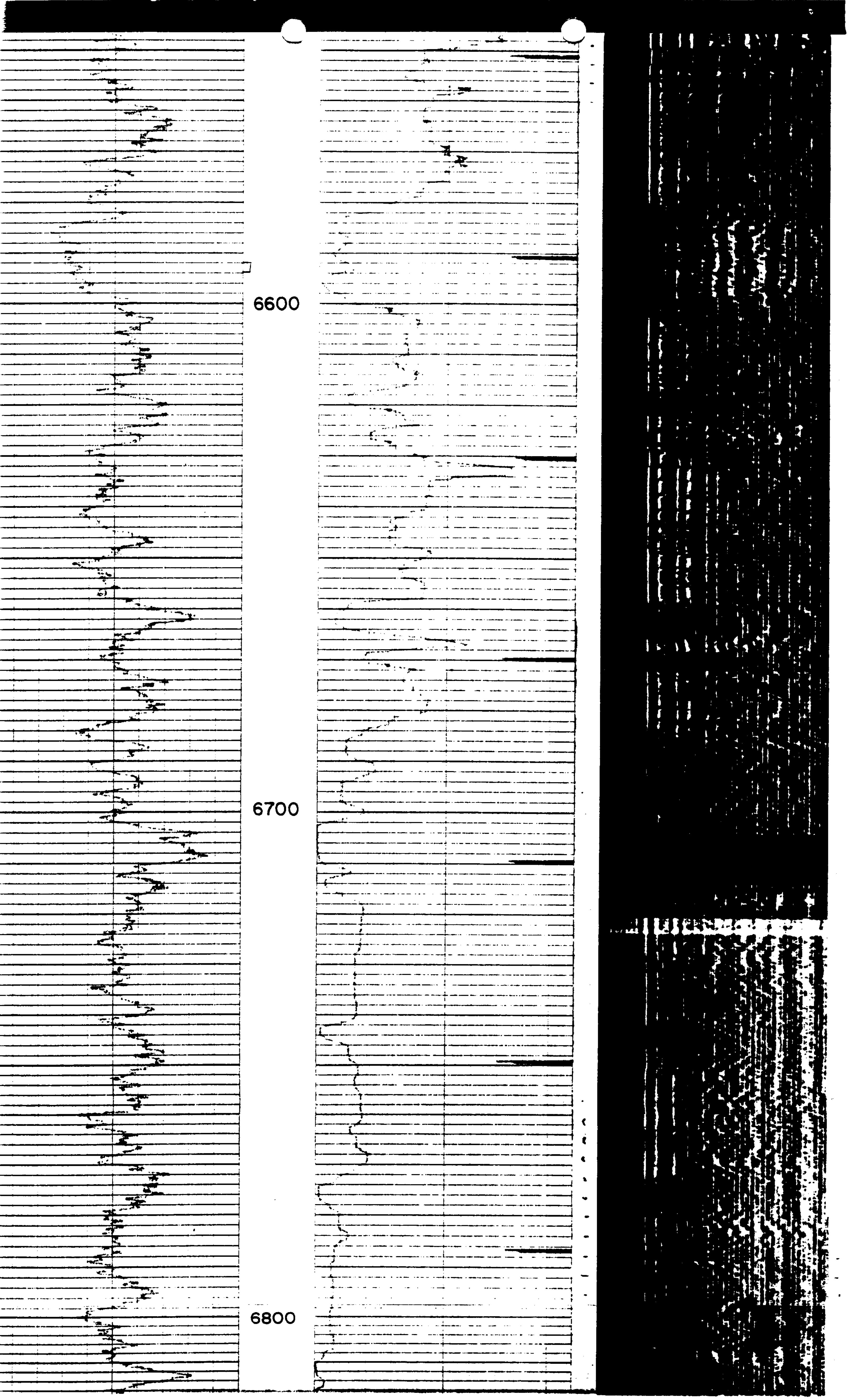
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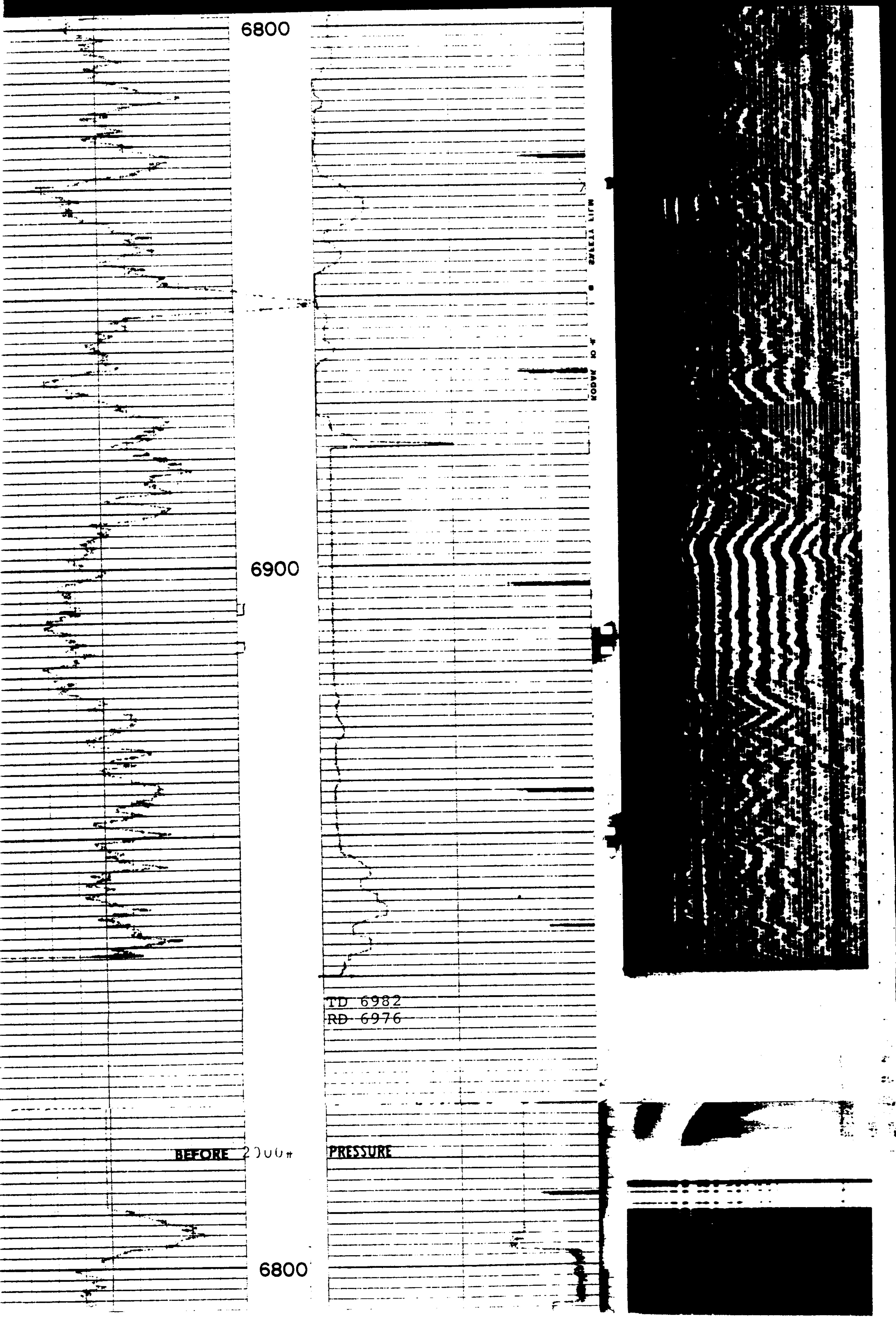
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TD 6982
RD 6976
BEFORE 2000#
PRESSURE
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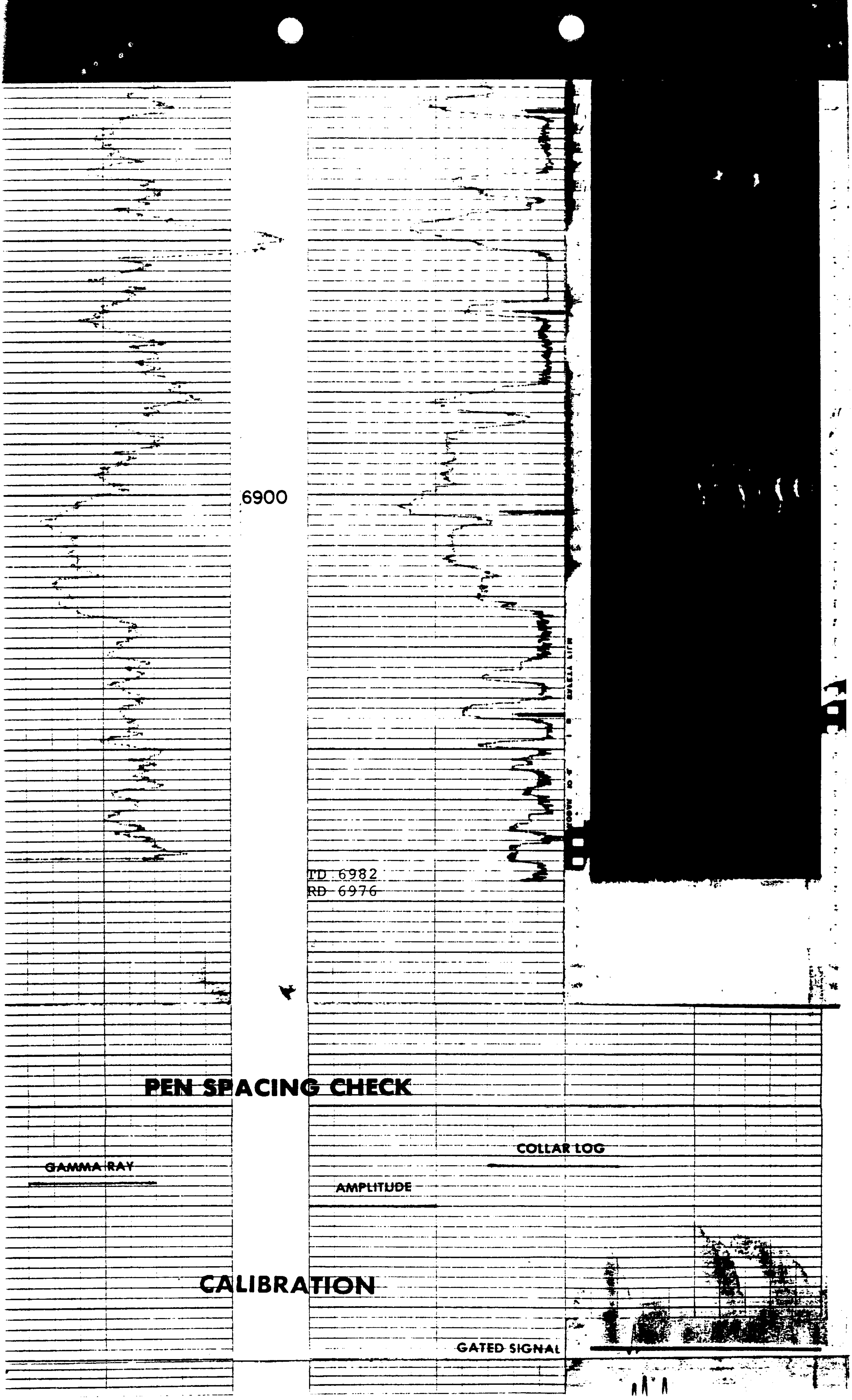
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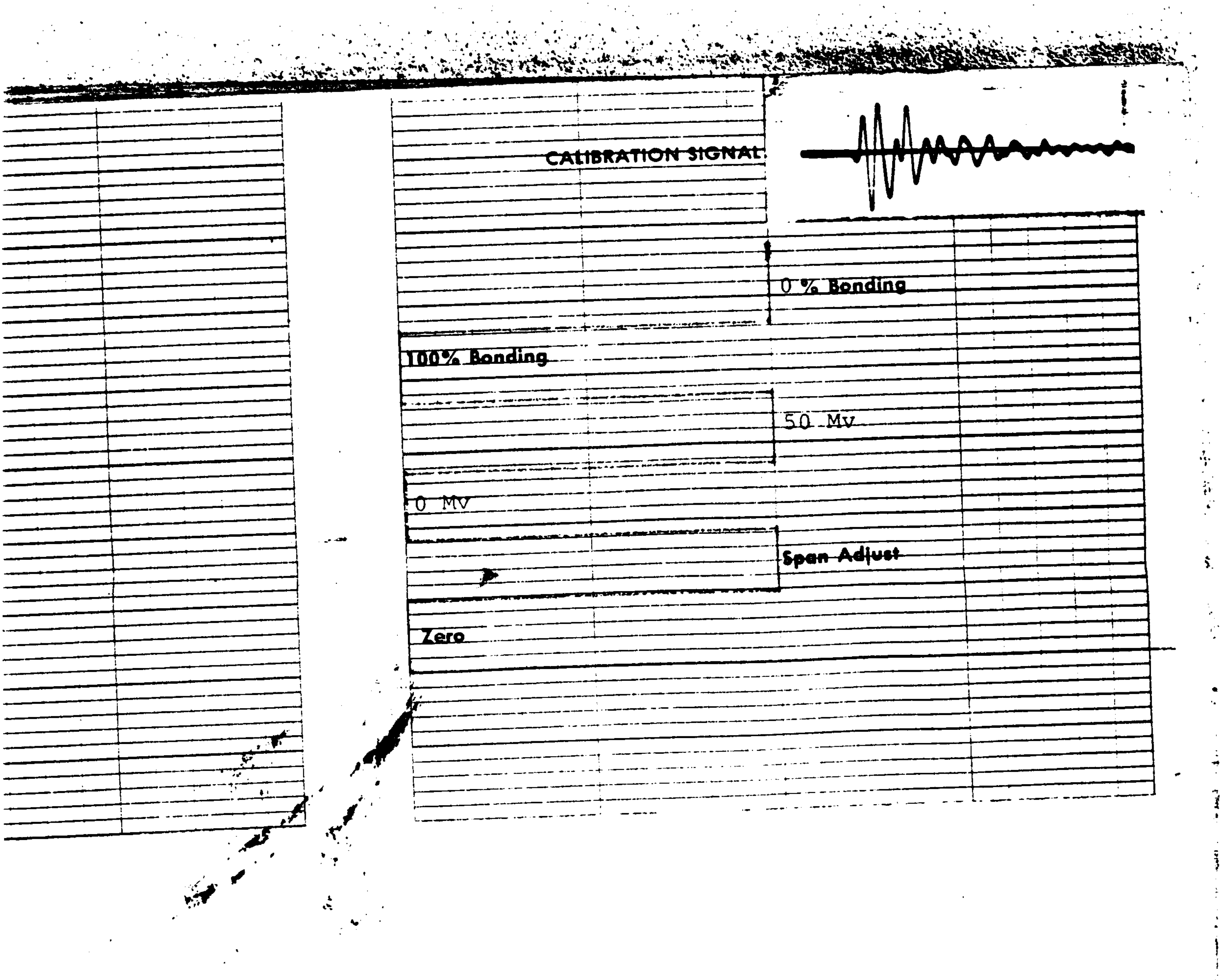
COLLAR LOG
GAMMA RAY
AMPLITUDE
CALIBRATION
GATED SIGNAL



CALIBRATION SIGNAL
0 % Bonding
100% Bonding
50 Mv
0 Mv
Span Adjust
Zero

MUD LOG

Baroid

BAROID LOGGING SYSTEMS

P O BOX 1675 HOUSTON, TEXAS 77001

COMPANY BELCO PETROLEUM CORPORATION

API No

WELL NATURAL BUTTES 21-20B

FIELD NATURAL BUTTES

COUNTY UINTAH STATE UTAH

API No

Location

Sec 20 Twp 9S Rge. 20E

Other Services:

Permanent Datum G.L., Elev 4771'

Log Measured From K.B., 14 Ft. Above Perm. Datum

Drilling Measured From K.B.

Elev. K.B 4785'

D.F 4783'

G.L 4771'

Logged 2500 Ft 7025 Ft

Date Logged 2-14-78 To 3-2-78

Depth Measured From K.B.

Supv. Eng. JIM HOLBEN Unit No R-7720

Type Mude BRINE-WATER To 4900 Ft

BRINE-DRISPAC To T.D. Ft

LEGEND

ABBREVIATIONS

NB NEW BIT
NCB NEW CORE BIT
CO CIRCULATED OUT
DST DRILL STEM TEST
LAT LOGGED AFTER TRIP
TG TRIP GAS
NR NO RETURNS
DS DIRECTIONAL SURVEY
DC DEPTH CORRECTION
CKF CHECK FOR FLOW
TCL TRIP CHLORIDES

MUD CHARACTERISTICS

W WEIGHT___LBS/GAL___LBS/CU FT
V VISCOSITY, API, SECONDS

LITHOLOGY

SAND
SHALE
CLAY
CHERT
SALT
SILTSTONE
CONGLOMERATE
LIMESTONE
OOLITIC LIMESTONE

This Heading and Log Conform To API RP 31

Baroid
Petroleum Services

NATURAL BUTTES 21-20 B
Y BELCO PETROLEUM CORP
N UINTAH CO., UTAH

LEGEND

TCL TRIP CHLORIDES
NB NEW BIT
NCB NEW CORE BIT
DST DRILL STEM TEST
TG TRIP GAS
NR NO RETURNS
EL ELECTRIC LOG
CO CIRCULATE OUT RETURNS
CKF CHECK FOR FLOW

SAND SHALE LIMESTONE DOLOMITE

BAROID LOGGING SYSTEMS
MUD LOG

NG RATE
PER HR.
PER FT.
5.0 7.5

VISUAL POROSITY
G S T

LITHOLOGY

DEPTH

DATE 12M AM

☐ ppm LOG-HYDROCARBONS IN MUD (M=1000)
☐ GAS LOG - % GAS IN MUD AIR/GAS ANALYSIS
☒ GAS LOG-UNITS OF GAS IN AIR

	C_1	C_2	C_3	C_4	C_{5+}
OM					
%					
UNITS	100 200				

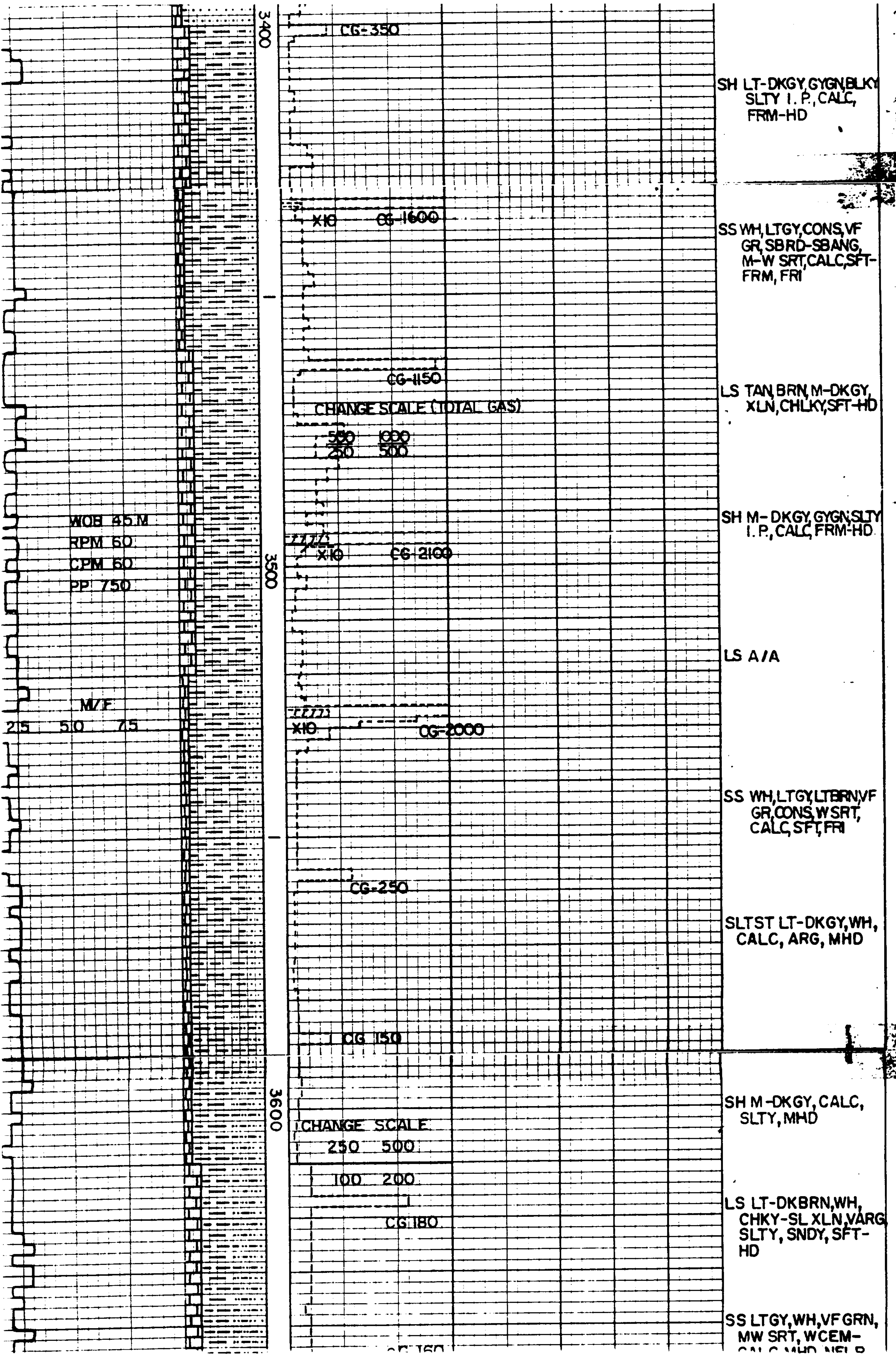
REMARKS

LOGGING 2-14-78
B 3/4"
184 F

DRLG WITH WATER

2500

LS LT-MBRN,VF-SL
XLN,VARG,SLSLTY,
SFT-HD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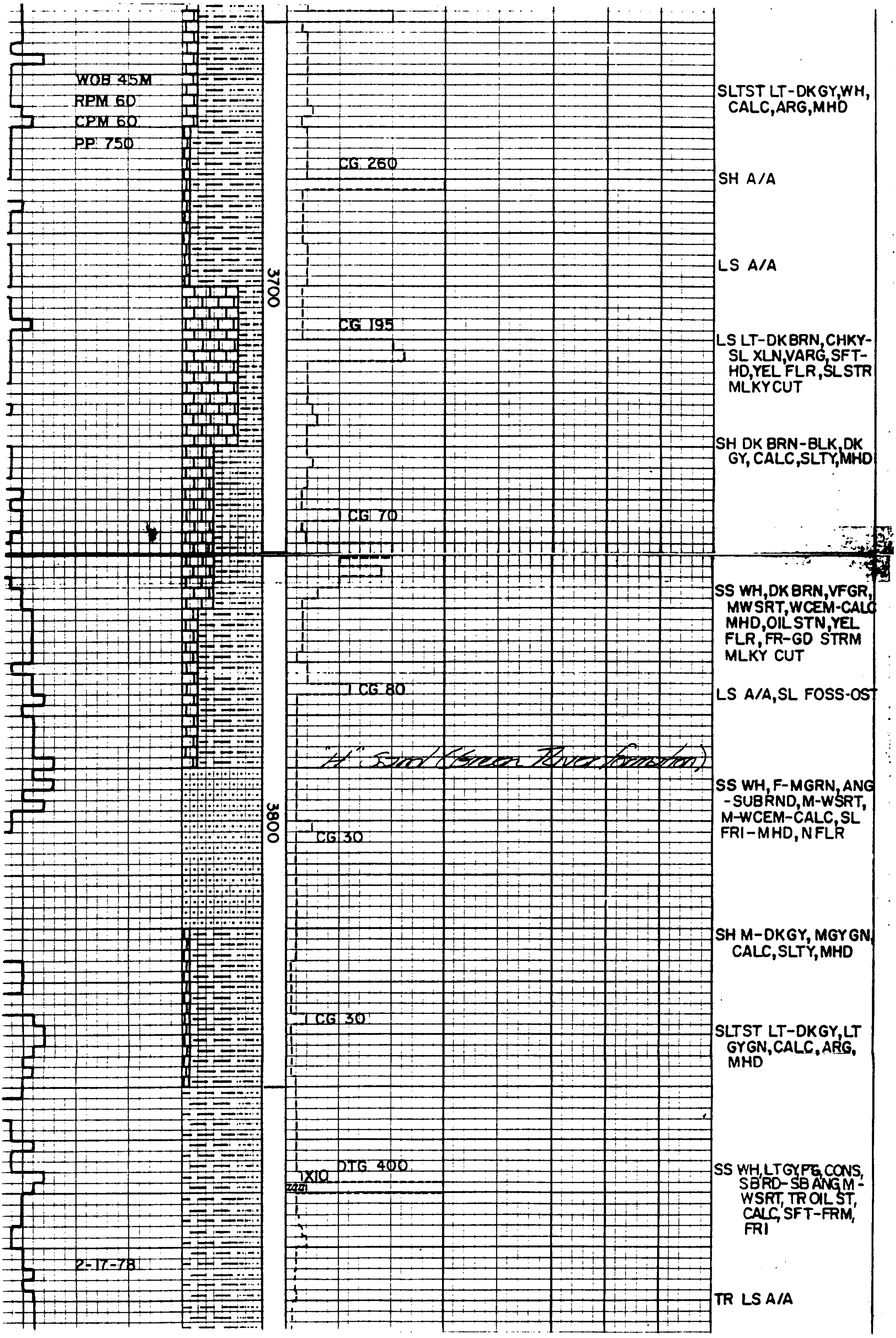
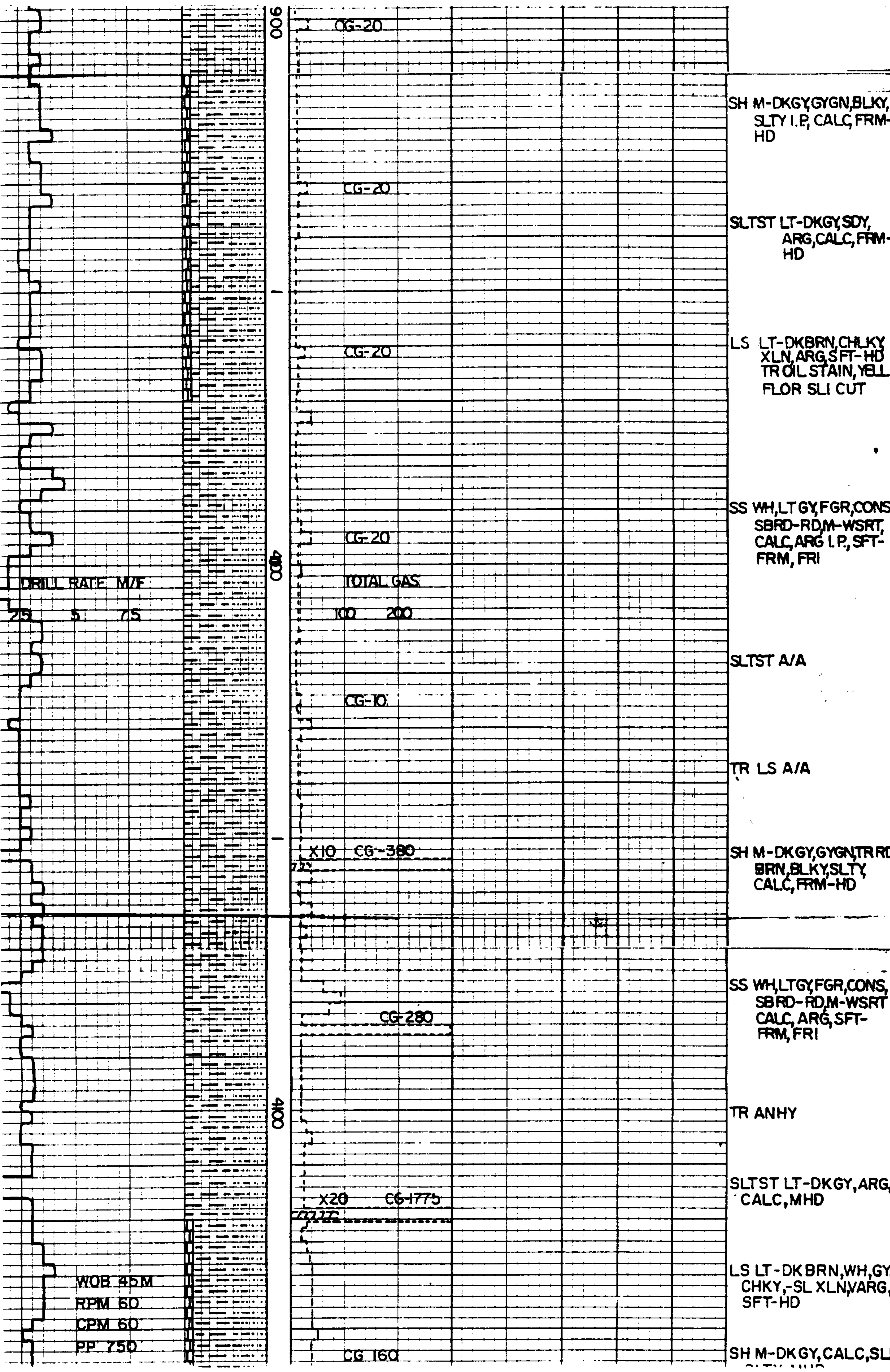
CG-350
SH LT-DKGY, GYGN, BLKY, SLTY I. P., CALC, FRM-HD
X10 CG-1600
SS WH, LTGY, CONS, VF GR, SBRD-SBANG, M-W SRT, CALC, SFT-FRM, FRI
CG-1150
CHANGE SCALE (TOTAL GAS)
500/250 1000/500
LS TAN, BRN, M-DKGY, XLN, CHLKY, SFT-HD
WOB 45 M
RPM 60
CPM 60
PP 750
SH M-DKGY, GYGN, SLTY I. P., CALC, FRM-HD
X10 CG-2100
3500
LS A/A
M/F
2.5 5.0 7.5
X10 CG-2000
SS WH, LTGY, LTBRN, VF GR, CONS, W SRT, CALC, SFT, FRI
CG-250
SLTST LT-DKGY, WH, CALC, ARG, MHD
CG 150
3600
SH M-DKGY, CALC, SLTY, MHD
CHANGE SCALE
250 500
100 200
CG 180
LS LT-DKBRN, WH, CHKY-SL XLN, VARG, SLTY, SNDY, SFT-HD
SS LTGY, WH, VF GRN, MW SRT, WCEM-


WOB 45M
RPM 60
CPM 60
PP 750
CG 260
3700
CG 195
CG 70
CG 80
"H" Sand (Green River formation)
3800
CG 30
CG 30
XIO
DTG 400
2-17-78
SLTST LT-DKGY,WH, CALC,ARG,MHD
SH A/A
LS A/A
LS LT-DKBRN,CHKY-SL XLN,VARG,SFT-HD,YEL FLR,SL STR MLKY CUT
SH DK BRN-BLK,DK GY, CALC,SLTY,MHD
SS WH,DK BRN,VFGR, MWSRT,WCEM-CALC MHD,OIL STN,YEL FLR, FR-GD STRM MLKY CUT
LS A/A,SL FOSS-OST
SS WH, F-MGRN, ANG -SUBRND,M-WSRT, M-WCEM-CALC, SL FRI-MHD, N FLR
SH M-DKGY, MGYGN, CALC,SLTY,MHD
SLTST LT-DKGY,LT GYGN,CALC,ARG, MHD
SS WH,LTGY,FG,CONS, SBRD-SBANG,M-WSRT, TR OIL ST, CALC, SFT-FRM, FRI
TR LS A/A



900
CG-20
SH M-DKGY,GYGN,BLKY, SLTY I.P, CALC, FRM-HD
CG-20
SLTST LT-DKGY,SDY, ARG,CALC, FRM-HD
LS LT-DKBRN,CHLKY XLN,ARG,SFT-HD TR OIL STAIN,YELL FLOR SLI CUT
CG-20
SS WH,LT GY,FGR,CONS SBRD-RD,M-WSRT, CALC,ARG I.P., SFT-FRM, FRI
CG-20
4000
DRILL RATE M/F
2.5 5 7.5
TOTAL GAS
100 200
SLTST A/A
CG-10
TR LS A/A
X10 CG-380
SH M-DKGY,GYGN,TR RD BRN,BLKY,SLTY, CALC,FRM-HD
SS WH,LTGY,FGR,CONS, SBRD-RD,M-WSRT CALC, ARG, SFT-FRM, FRI
CG-280
4100
TR ANHY
SLTST LT-DKGY,ARG, CALC,MHD
X20 CG-1775
LS LT-DK BRN,WH,GY CHKY,-SL XLN,VARG, SFT-HD
WOB 45M
RPM 60
CPM 60
PP 750
CG 160
SH M-DKGY,CALC,SL

Dresser Atlas

COMPENSATED **Densilog**

FILE NO. 501

COMPANY BELCO PETROLEUM CORP.

WELL NATURAL BUTTES 21-20B

FIELD NATURAL BUTTES

COUNTY UINTAH STATE UTAH

LOCATION: SW NE NE

SEC 20 TWP 9S RGE 20E

Other Services: DLL/GR, F LOG

Permanent Datum G.L. Elev. 4769

Log Measured from K.B. 16 Ft. Above Permanent Datum

Drilling Measured from K.B.

Elevations: KB 4785, DF 4784, GL 4769

Date	3/1/78			
Run No.	ONE			
Depth—Driller	7025			
Depth—Logger	7028			
Bottom Logged Interval	7026			
Top Logged Interval	1400			
Casing—Driller	9 5/8 @ 196	@	@	@
Casing—Logger	196			
Bit Size	7 7/8 8 3/4			
Type Fluid in Hole	BRINE/DRISPAC			
Density and Viscosity	10.6 42			
pH and Fluid Loss	8.5 7.6 cc	cc	cc	cc
Source of Sample	FLOWLINE			
Rm @ Meas. Temp.	.18 @ 56 °F	@ °F	@ °F	@ °F
Rmf @ Meas. Temp.	.13 @ 68 °F	@ °F	@ °F	@ °F
Rmc @ Meas. Temp.	.54 @ 68 °F	@ °F	@ °F	@ °F
Source of Rmf and Rmc	MEAS MEAS			
Rm @ BHT	.07 @ 142 °F	@ °F	@ °F	@ °F
Time Since Circ.	10 HRS			
Max. Rec. Temp. Deg. F.	142 °F	°F	°F	°F
Equip. No. and Location	6159 RSVT			

FOLD HERE

Remarks:

Equipment Used				
Series No.	2208	1306		
Run No.	ONE	ONE		
S.O.	87766	87766		
Tool No.	29227	24543		
Elec. No.				
Panel No.	37004	34481		

Equipment Data

Gamma Ray			
Run No.	ONE		
Tool Model No.	1306		
Serial No.	24543		
Diam.	3 5/8"		
Detect. Model No.	D6N4		
Type	SCINT		
Length	6"		
Dist. to Source	14'		

Densilog			
Run No.	ONE		
Tool Model No	2208		
Serial No.	29227		
Diam.	3"		
Computer Model No.	3457		
Serial No.	37004		
Source Model No.	S3F20		
Serial No.	C-116		

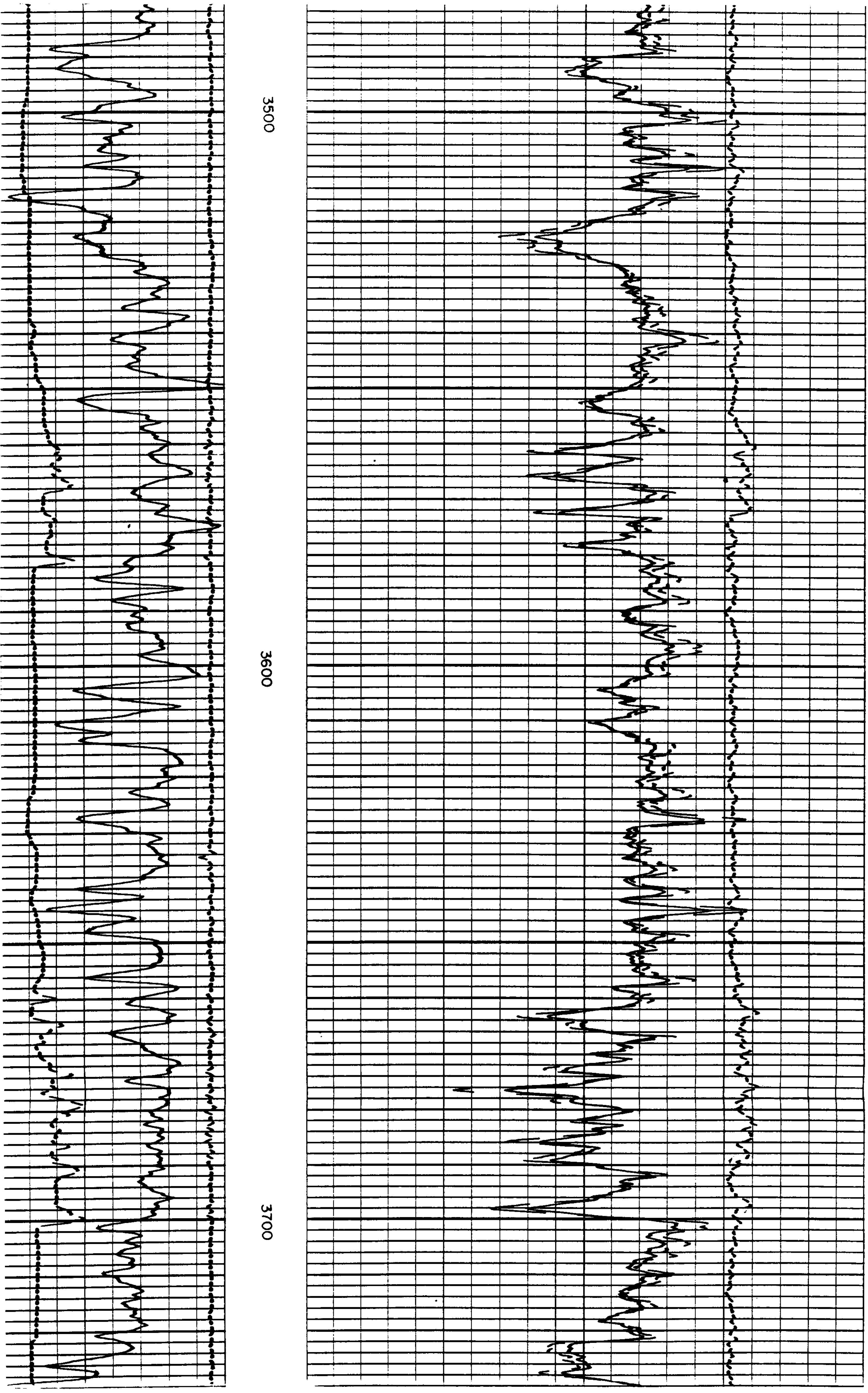
General			
Hoist Truck No.	HL6159		
Auxiliary Equipment			

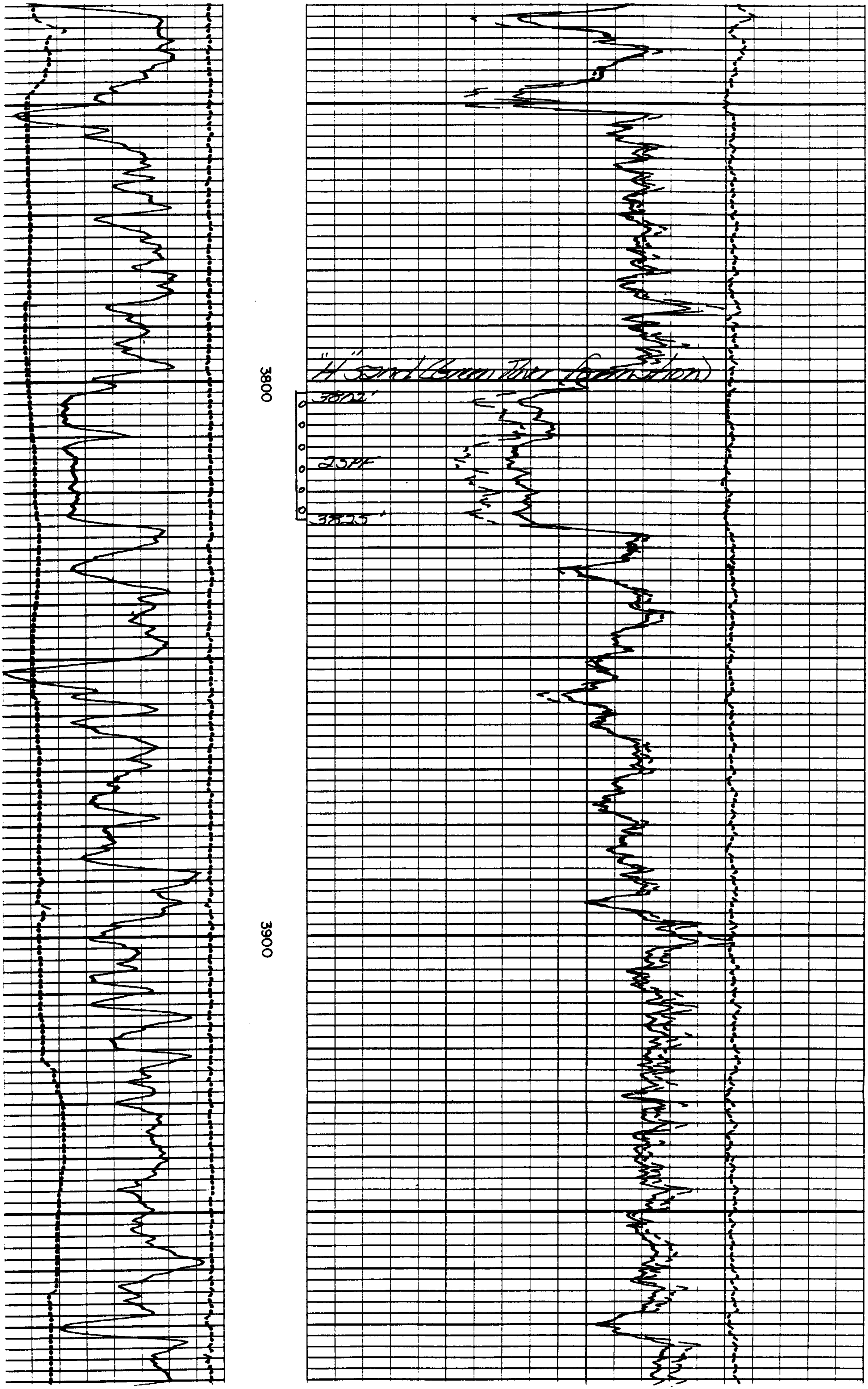
Computer Data

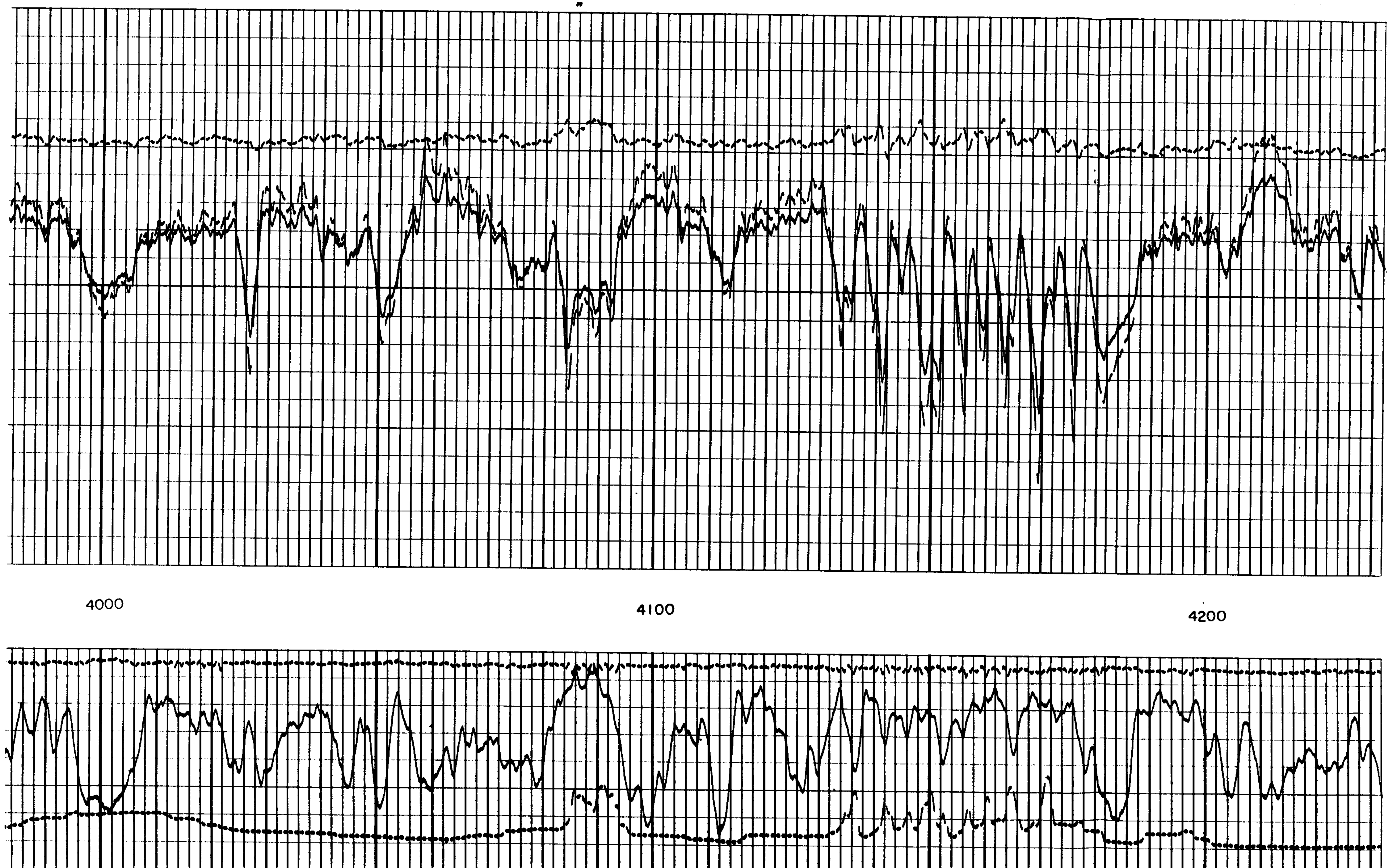
Logging Data

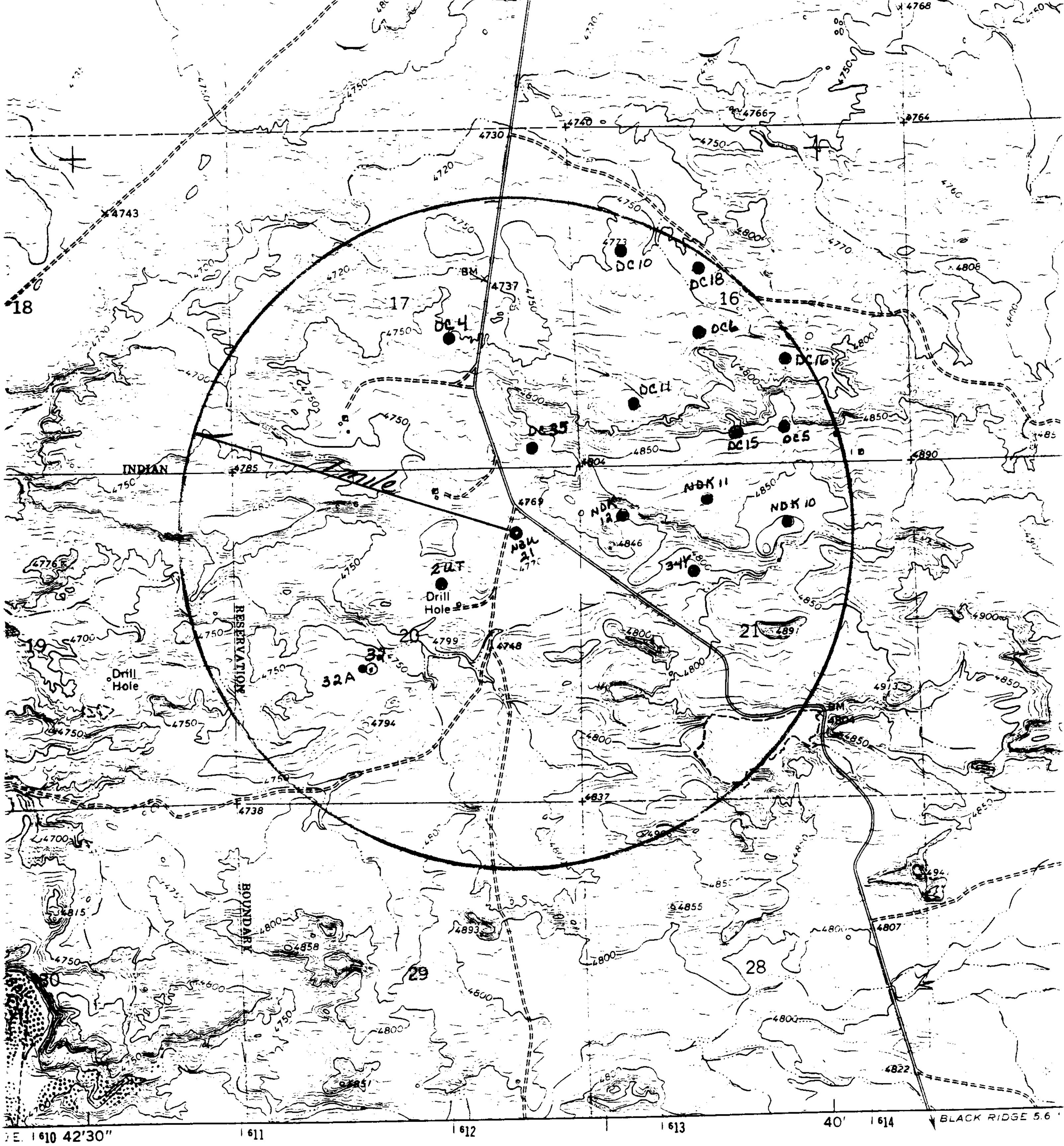
Run No.	General: Depths From	Depths To	Speed Ft./Min.	Densilog: T.C. Sec.	Density Scale	Correction Scale	Porosity Scale Data	Gamma Ray: T.C. Sec.	Sens. Settings	Zero Div. L or R	API G.R. Units/Div.
	7028	1400	30	2	2.0-3.0	-.5-+.5	0-30%	2	548	0	15

GAMMA RAY & CALIPER	DEPTH	BULK DENSITY GRAMS/CC
← Tension Curve		CORRECTION -.5 0 +.5


3500
3600
3700


3800
"H" Sand (Green River Formation)
3802'
2SPF
3825'
3900


4000
4100
4200



SCALE 1:24000

1 ½ 0 1 MILE

1000 0 1000 2000 3000 4000 5000 6000 7000 FEET

1 .5 0 1 KILOMETER

CONTOUR INTERVAL 10 FEET
DOTTED LINES REPRESENT 5-FOOT CONTOURS
DATUM IS MEAN SEA LEVEL

EXHIBIT IIA

UTAH

QUADRANGLE LOCA

IC NORTH
F SHEET

THIS MAP COMPLIES WITH NATIONAL MAP ACCURACY STANDARDS
U.S. GEOLOGICAL SURVEY, DENVER, COLORADO 80225, OR WASHINGTON, D.C. 20242

DOWELL SCHLUMBERGER INCORPORATED

LABORATORY LOCATION Vernal, Utah

API WATER ANALYSIS REPORT FORM

DATE 8-16-91

LAB NO. 1503-00458

Company	Sample No.	Date Sampled
Enron Oil and Gas	1	8-14-91

Field	Legal Description	County or Parish	State
Chapita Wells	Sec. 26, T9S, R22E	Uintah	Utah

Lease or Unit	Well	Depth	Formation	Water, B/D
Chapita Wells	301-26	±6000'	Wasatch	

Type of Water (Produced, Supply, etc.)	Sampling Point	Sampled By
Produced	Well head	JG

DISSOLVED SOLIDS

CATIONS	mg/L	me/L
Sodium, Na (calc.)	6325	272
Calcium, Ca	940	47
Magnesium, Mg	132	11
Barium, Ba	—	—

ANIONS	mg/L	me/L
Chloride, Cl	8600	241
Sulfate, SO_4	4000	80
Carbonate, CO_3	0	0
Bicarbonate, HCO_3	549	9

Total Dissolved Solids (calc.) 20546

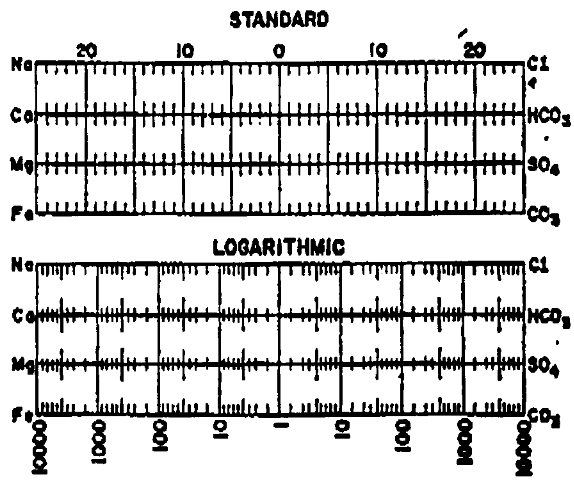
Iron, Fe (total) 3 mg/l

Sulfide, as H_2S —

OTHER PROPERTIES

pH	7.0
Specific Gravity, 60/60 F.	1.010
Resistivity (ohm-meters) ____ F.	

WATER PATTERNS — me/L



REMARKS & RECOMMENDATIONS:

ANALYSIS BASED ON API RECOMMENDED PROCEDURE

EXHIBIT X

WELLBORE DIAGRAM

NATURAL BUTTES UNIT 21-20 B
NENE, SECTION 20, T9S, R20E
UINTAH COUNTY, UTAH

ELEVATIONS
GL: 4769'
KB: 4785'

CASING HEAD: 11" 3000#
TUBING HEAD: 11" 3000# x 6" 3000#
TREE: 2 1/16" X 3000# MASTER VALVES

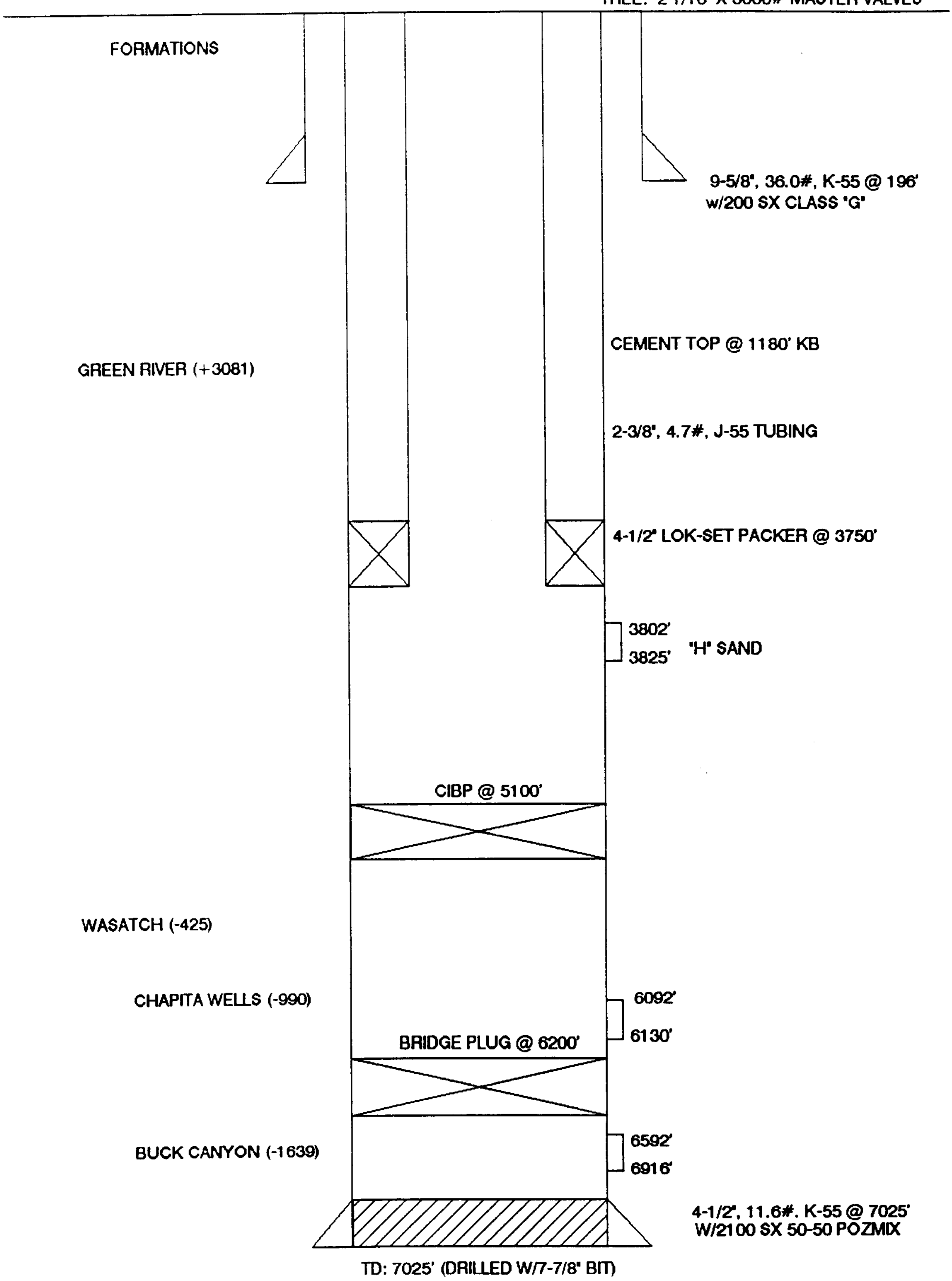


EXHIBIT IV

Prepared in cooperation with the
DIVISION OF OIL, GAS, AND MINING

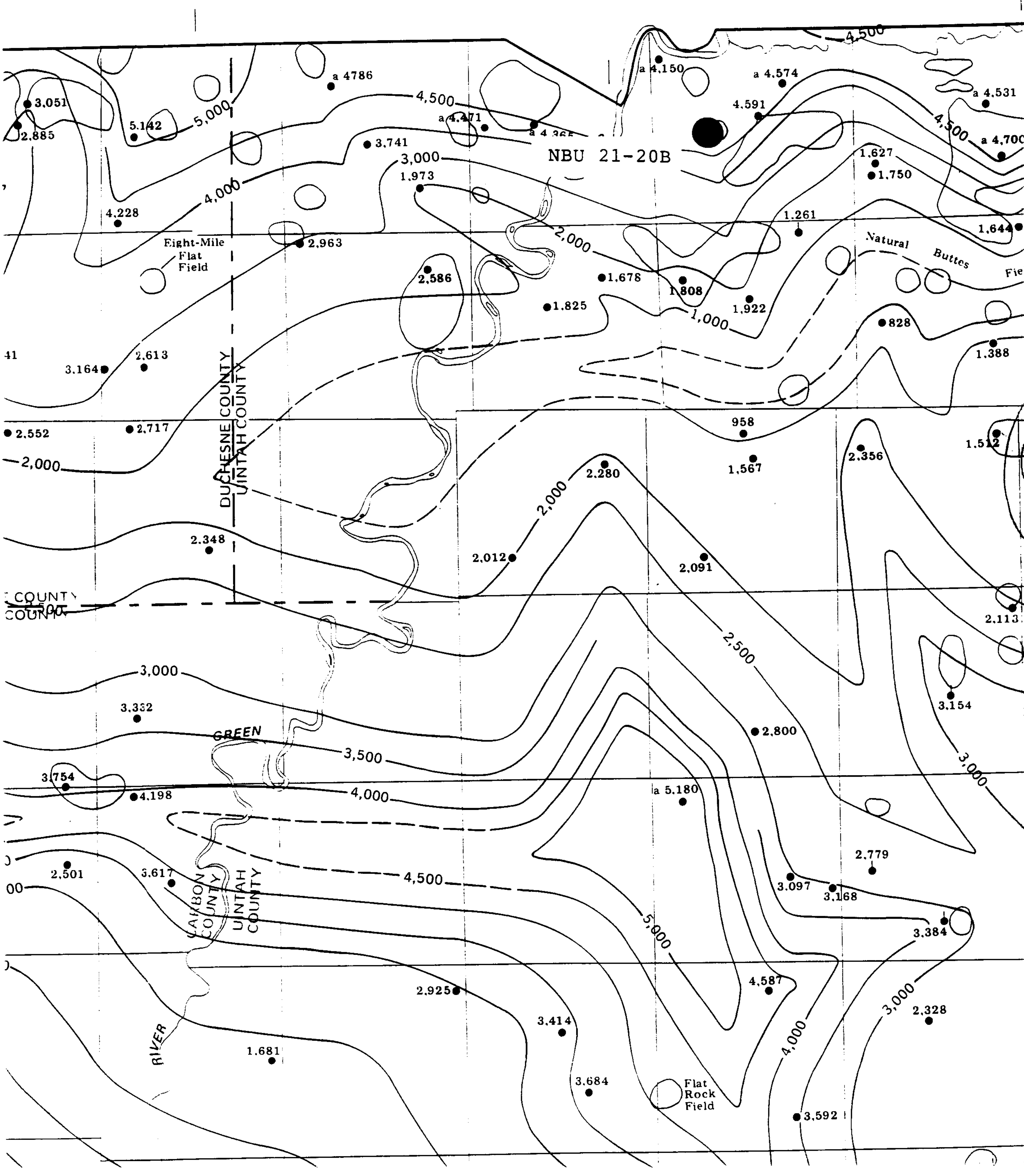
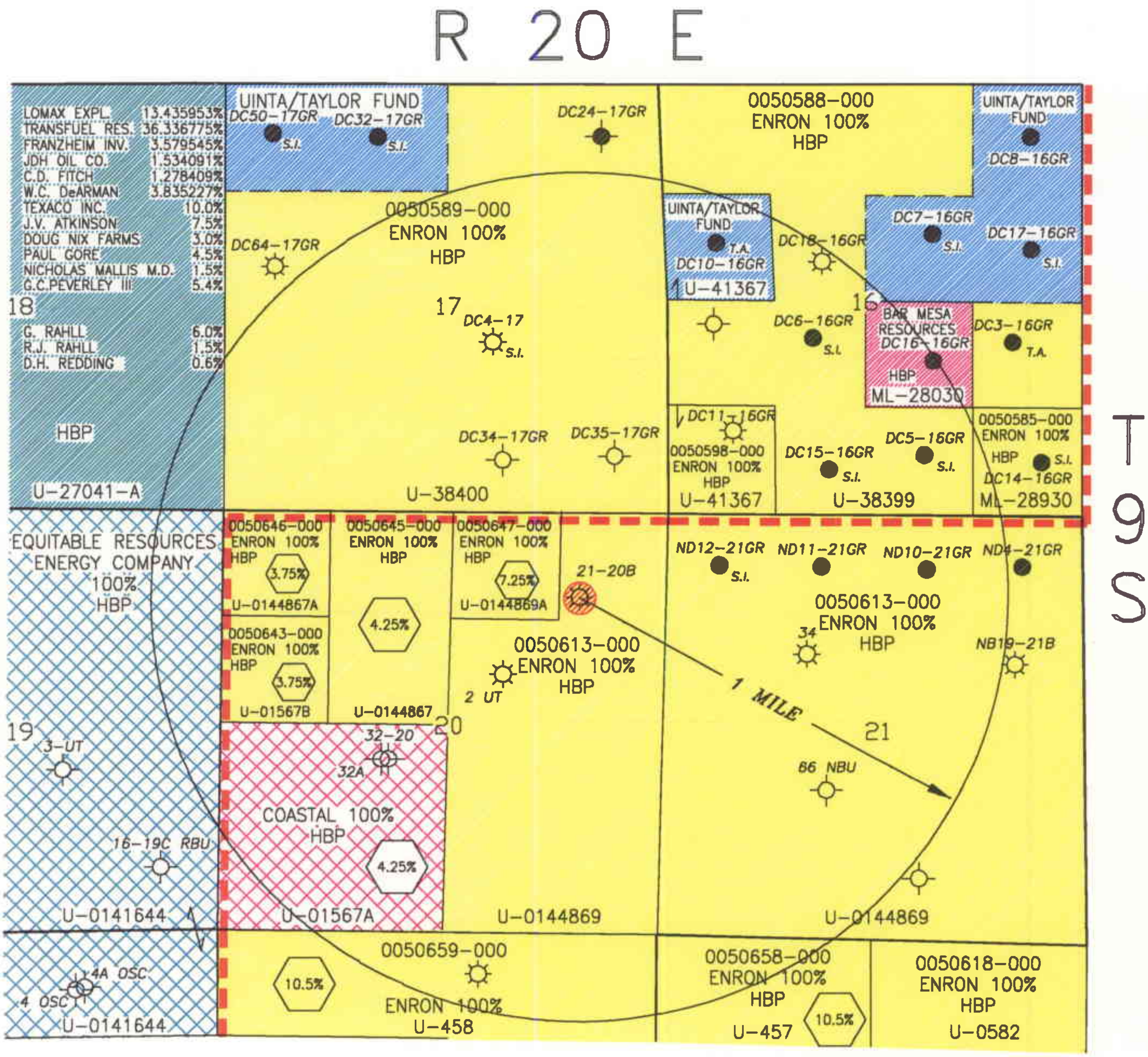


EXHIBIT II



GREEN RIVER FORMATION OWNERSHIP

- *ENRON OIL & GAS COMPANY 100%*
- *COASTAL OIL & GAS CORPORATION 100%*
- *UINTA/TAYLOR FUND, a California Ltd. Partnership 100%*
- *BAR MESA RESOURCES, INC. 100%*
- *EQUITABLE RESOURCES ENERGY COMPANY 100%*
- *TRANSFUEL RESOURCES COMPANY, et al 100%*

NATURAL BUTTES UNIT OUTLINE

PROPOSED INJECTION WELL

ENRON ORRI

SURFACE OWNERSHIP

USA – IN TRUST FOR UTE INDIAN TRIBE

ENRON Oil & Gas Company

INJECTION WELL APPLICATION

NBU 21-20B

UINTAH COUNTY, UTAH

Scale:	Map ID	Author	Date:
1" = 2000'	NBU21_20	T.L.MILLER	3/92

Western Atlas International
A Litton/Dresser Company

CORE LABORATORIES

LAB #: 920203-1

02-12-1992

ENRON OIL AND GAS

WELL #: #21-20-B
COUNTY: Uintah STATE: Utah
FORMATION: Green River
DATE SAMPLED: 1/24/92
REMARKS: PERFS 3802'-3825'
NBU #21-20-B
GREEN RIVER

FIELD: Natural Buttes
LOCATION: Sec. 20, T9S, R20E
INTERVAL: 3802 - 25'
SAMPLE ORIGIN: Swab sample

	MG/L	MEQ/L
SODIUM	14400	626.40
POTASSIUM	121	3.10
CALCIUM	471	23.50
MAGNESIUM	145	11.92
TOTAL CATIONS		664.92

	MG/L	MEQ/L
SULFATE	16200	336.96
CHLORIDE	10200	287.64
CARBONATE	0	0.00
BICARBONATE	1086	17.81
HYDROXIDE	0	0.00
TOTAL ANIONS		642.41

	MG/L
CALC. SODIUM	13882
NACL EQUIVALENT	37399
CALC TDS* @356 F	42072
API TDS* @221 F	42623

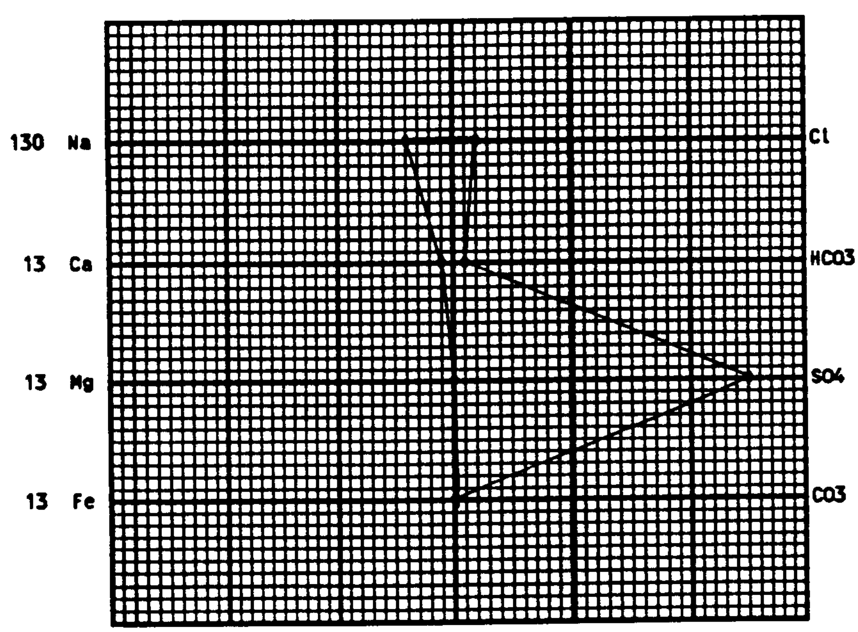
SPECIFIC RESISTANCE AT 68F (OHM-M):
OBSERVED 0.25

OBSERVED pH 7.6

* TOTAL DISSOLVED SOLIDS

WATER ANALYSIS PATTERN
Scale
MEQ per Unit

(Na value in graph includes Na and K)



NOTE: MG/L = milligrams per liter
MEQ/L = milligram equivalent per liter

Sodium Chloride equivalent by Dunlap & Hawthorne - calculation from components

APPROVED BY: Shari Davis

EXHIBIT III

WELL DATA SHEET (WELLS WITHIN AREA OF REVIEW)

WELL NAME	CURRENT STATUS	SPUD/TD	CASING	TOP OF CEMENT	CEMENT	PERFORATIONS	FORMATION
DUCK CREEK 4-17GR 2050' FSL - 1970' FEL NWSE, SEC. 17, T9S, R20E	PRODUCING-GAS	3/81 7331'	9-5/8", 36#, K-55 @ 189' 7", 20 & 23#, K-55 @ 5176' 4-1/2", 11.6#, K-55 @ 7339'	1750'	200 SX CLASS "G" CEMENT 996 SX 50-50 POZMIX 500 SX 50-50 POZMIX	7047-49' 6660-62' & 6653-55' 6365-67' 6130-32'	B-11 B-7 C-STRAY C-11
DUCK CREEK 5-16GR 539' FSL - 2000' FEL SWSE, SEC. 16, T9S, R20E	SI-OIL	7/79 5095'	9-5/8", 36#, K-55 @ 210' 5-1/2", 15.5#, NKK @ 5093'	1530'	200 SX CLASS "H" CEMENT 960 SX 50-50 POZMIX	4913-17' 4839-43'	M-8 M-4
DUCK CREEK 6-16GR 2082' FSL - 1925' FWL NESW, SEC. 16, T9S, R20E	SI-OIL	8/79 5054'	9-5/8", 36#, K-55 215' 5-1/2, 15.5#, NKK @ 5054'	1515'	200 SX CLASS "H" CEMENT 1161 SX 50-50 POZMIX	4870-74' & 4862-64'	M-8
DUCK CREEK 10-16GR 714' FWL - 1984' FNL SWNW, SEC. 16, T9S, R20E	SI-OIL	11/80 5072'	9-5/8", 36#, K-55 @ 194' 5-1/2", 17#, K-55 @ 5070'	1460'	200 SX CLASS "G" CEMENT 930 SX 50-50 POZMIX	4921-23' 4893-95'	M-STRAY M-8
DUCK CREEK 11-16GR 864' FWL - 968' FSL SWSW, SEC. 16, T9S, R20E	PRODUCING-OIL	10/80 5007'	9-5/8", 36#, K-55 @ 204' 5-1/2", 17#, NKK @ 5001'	1648'	200 SX CLASS "G" CEMENT 820 SX 50-50 POZMIX	4953-55' & 4936-38' 4852-54' & 4845-47' 4092-4102' & 4109-12' (CIBP @ 4100')	M-STRAY M-8 J-ZONE J-ZONE
DUCK CREEK 15-16GR 1970' FWL - 465' FSL SESW, SEC. 16, T9S, R20E	SI-OIL	4/80 5090'	9-5/8", 36#, K-55 208' 5-1/2", 17#, NKK @ 5090'	2020'	200 SX CLASS "G" CEMENT 1060 SX 50-50 POZMIX	4917-21' & 4909-13' 4840-43'	M-STRAY M-4
DUCK CREEK 16-16GR 1658' FSL - 1931' FEL NWSE, SEC. 16, T9S, R20E	SI-OIL	4/80 5064'	9-5/8", 36#, K-55 @ 208' 5-1/2", 17#, NKK @ 5063'	1650'	200 SX CLASS "G" CEMENT 1105 SX 50-50 POZMIX	4856-64' 4778-89'	M-8 M-4
DUCK CREEK 18-16GR 1945' FWL - 2210' FNL SENE, SEC. 16, T9S, R20E	PRODUCING-GAS	7/80 7270'	9-5/8", 36#, K-55 @ 192' 5-1/2", 17#, K-55 @ 7265' KB	1780'	200 SX CLASS "G" CEMENT 2175 SX 50-50 POZMIX	6985-87' 7014-16' 7071-73'	B-11 B-11 B-11

EXHIBIT III

WELL DATA SHEET (WELLS WITHIN AREA OF REVIEW)

WELL NAME	CURRENT STATUS	SPUD/TD	CASING	TOP OF CEMENT	CEMENT	PERFORATIONS	FORMATION
DUCK CREEK 35-17GR P&A PLUGS 306' FSL - 767' FEL ESE, SEC. 17, T9S, R20E	P&A'D 6-11-81	5/81 5006'	9-5/8", 36#, K-55 @ 184'	SURFACE	200 SX CLASS "G" CEMENT 80 SX CLASS "G" CEMENT 80 SX CLASS "G" CEMENT 100 SX CLASS "G" CEMENT 100 SX CLASS "G" CEMENT 100 SX CLASS "G" CEMENT 50 SX CLASS "G" CEMENT	4688-4488' 4205-4000' 3722-3522' 2190-1990' 1102-992' 267-167'	
NBU 34Y 1690' FNL - 1702' FWL SENW, SEC. 21, T9S, R20E	SI-OIL	12/79 7206'	9-5/8", 43.5#, K-55 @ 203' 4-1/2", 11.6#, N-80 @ 7200' KB		120 SX CLASS "H" CEMENT 2355 SX 50-50 POZMIX	4824-26' 4733-35' 4056-66' CIBP @ 4200'	M-4 M-2 J-2
NATURAL DUCK 10-21GR 913' FNL - 2017' FEL SWNE, SEC. 21, T9S, R20E	PRODUCING-OIL	12/80 5078'	9-5/8", 36#, K-55 @ 195' 5-1/2", 17#, K-55 @ 5078'	1900'	200 SX CLASS "G" CEMENT 700 SX 50-50 POZMIX	5012-14' 4882-84' 4812-14' & 4805-07' 4778-80'	M-STRAY M-8 M-4 M-2
NATURAL DUCK 11-21GR 542' FNL - 1976' FWL NENW, SEC. 21, T9S, R20E	SI-OIL	2/81 5070'	9-5/8", 36#, K-55 @ 190' 5-1/2", 17#, K-55 @ 5070'	1350'	200 SX CLASS "G" CEMENT 1011 SX 50-50 POZMIX	4845-47' & 4850-52'	M-4
ATURAL DUCK 12-21GR 666' FWL - 824' FNL NWNW, SEC. 21, T9S, R20E	SI-OIL	5/81 4993'	9-5/8", 36#, K-55 @ 208' 5-1/2", 17#, K-55 @ 4992'	1350'	200 SX CLASS "G" CEMENT 905 SX 50-50 POZMIX	4796-98' & 4790-92' 4730-32'	M-6 M-STRAY
CIGE 32-30 NESW, SEC. 20, T9S, R20E	P&A'D	280'	9-5/8" @ 280'	SURFACE			
CIGE 32A-20 NESW, SEC. 20, T9S, R20E	TA	7332'	4-1/2"	1500'		6421-23' 6918-30'	
U TRAIL 2 UT RE-ENTRY SWNE, SEC. 20, T9S, R20E	P&A'D P&A'D	10,498 6407	5-1/2"		350 SX CEMENT	6075-85 6193-95'	

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, DC 20460

EPA

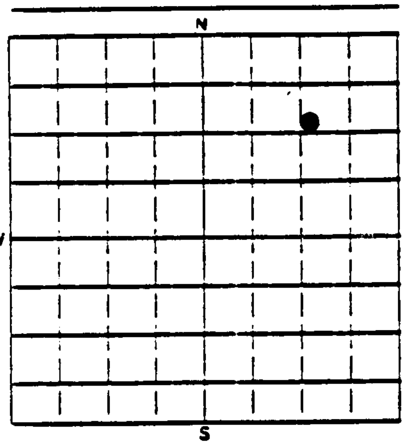
COMPLETION REPORT FOR BRINE DISPOSAL, HYDROCARBON STORAGE, OR ENHANCED RECOVERY WELL

Form Approved
OMB No. 2040-0042
Approval expires 9-30-86

NAME AND ADDRESS OF EXISTING PERMITTEE
ENRON OIL & GAS COMPANY
P.O. BOX 250
BIG PINEY, WYOMING 83113

NAME AND ADDRESS OF SURFACE OWNER
UTE TRIBE
Ft. DUCHESNE, UTAH

LOCATE WELL AND OUTLINE UNIT ON SECTION PLAT — 640 ACRES



STATE	COUNTY	PERMIT NUMBER
UTAH	UINTAH	UT2623-03708

SURFACE LOCATION DESCRIPTION
NE ¼ OF NE ¼ OF NE ¼ SECTION 20 TOWNSHIP 9S RANGE 20E

LOCATE WELL IN TWO DIRECTIONS FROM NEAREST LINES OF QUARTER SECTION AND DRILLING UNIT
Surface Location 1037 ft. from (N/S) ____ Line of quarter section
and 1033 ft. from (E/W) ____ Line of quarter section

WELL ACTIVITY
- [X] Brine Disposal
- [ ] Enhanced Recovery
- [ ] Hydrocarbon Storage

TYPE OF PERMIT
- [X] Individual
- [ ] Area

Number of Wells 1

Estimated Fracture Pressure of Injection Zone

Anticipated Daily Injection Volume (Bbls) Average	Maximum	Injection Interval Feet	to Feet
700 Bbls	1400 Bbls	3802'	3825'

Anticipated Daily Injection Pressure (PSI) Average	Maximum	Depth to Bottom of Lowermost Freshwater Formation (Feet)
500 psig	600 psig	200'

Type of Injection Fluid *(Check the appropriate block(s))*
- [X] Salt Water
- [ ] Brackish Water
- [ ] Fresh Water
- [ ] Liquid Hydrocarbon
- [ ] Other

Lease Name	Well Number
NATURAL BUTTES UNIT	21-20B SWD

Name of Injection Zone
GREEN RIVER "H" SAND

Date Drilling Began	Date Well Completed	Permeability of Injection Zone
2-9-78	5-18-78	10-20 md (estimated)

Date Drilling Completed	Porosity of Injection Zone
3-3-78	14%

CASING AND TUBING			CEMENT		HOLE	
OD Size	Wt/Ft — Grade — New or Used	Depth	Sacks	Class	Depth	Bit Diameter
9-5/8"	36#, K-55 New	196'	200	"G"		12-1/4"
4-1/2"	11.6#, J-55 New	7025'	2100	50/50 Pozmix		7-7/8"
2-3/8"	4.7#, J-55 New	3798'				

INJECTION ZONE STIMULATION		WIRE LINE LOGS, LIST EACH TYPE	
Interval Treated	Materials and Amount Used	Log Types	Logged Intervals
3802-25'	3500 gals 15% HCl, 2000# 16/30	Compensated Densilog	7028-1400'
	sand.	"F" Log	7028-1100'
		Dual Laterolog	7028- 196'
		GR-Bond Log	6982-1145'

Complete Attachments A — E listed on the reverse.

CERTIFICATION

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32).

NAME AND OFFICIAL TITLE *(Please type or print)*	SIGNATURE	DATE SIGNED
C.C. Parsons, District Manager	C C Parsons	9-17-92

EPA Final Permit No. [illegible]

Form Ap — OMB No. 2000-0042. Approval expires 9-30-86

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, DC 20460

EPA

WELL REWORK RECORD

NAME AND ADDRESS OF PERMITTEE
ENRON OIL & GAS COMPANY
P.O. BOX 250
BIG PINEY, WYOMING 83113

NAME AND ADDRESS OF CONTRACTOR
TEMPLES OIL WELL SERVICE, INC.
P.O. BOX 765
VERNAL, UTAH 84078

LOCATE WELL AND OUTLINE UNIT ON SECTION PLAT — 640 ACRES

N / W / E / S

STATE	COUNTY	PERMIT NUMBER
UTAH	UINTAH	UT2623-03708

SURFACE LOCATION DESCRIPTION
NE ¼ OF NE ¼ OF NE ¼ SECTION 20 TOWNSHIP 9S RANGE 20E

LOCATE WELL IN TWO DIRECTIONS FROM NEAREST LINES OF QUARTER SECTION AND DRILLING UNIT

Surface Location 1037 ft. from (N/S) N Line of quarter section
and 1033 ft. from (E/W) E Line of quarter section

WELL ACTIVITY
☒ Brine Disposal
☐ Enhanced Recovery
☐ Hydrocarbon Storage

Lease Name: NATURAL BUTTES UNIT

Total Depth Before Rework: 7025'
Total Depth After Rework: 7025' (CIBP @ 5100')
Date Rework Commenced: 1-23-92
Date Rework Completed: 9-11-92

TYPE OF PERMIT
☒ Individual
☐ Area
Number of Wells 1

Well Number: 21-20B SWD

WELL CASING RECORD — BEFORE REWORK

Casing		Cement		Perforations		Acid or Fracture Treatment Record
Size	Depth	Sacks	Type	From	To	
9-5/8"	196'	200	"G"			
4-1/2"	7025'	2100	50/50 Poz	6092'	6916'	86,817 gals 3% KCl MY-T-Gel III, 52,000# 100 mesh sand & 160,000# 20/40 sand.

WELL CASING RECORD — AFTER REWORK *(Indicate Additions and Changes Only)*

Casing		Cement		Perforations		Acid or Fracture Treatment Record
Size	Depth	Sacks	Type	From	To	
SAME AS	ABOVE			3802'	3825'	3500 15% HCl & 2000# 16/30 sand.

DESCRIBE REWORK OPERATIONS IN DETAIL — USE ADDITIONAL SHEETS IF NECESSARY

See attached Sundry Notice Form 3160-5

WIRE LINE LOGS, LIST EACH TYPE

Log Types	Logged Intervals
Compensated-Densilog	7028-1400'
"F" Log	7028-1100'
Dual Laterolog	7028- 196'
GR-Bond Log	6982-1145'

CERTIFICATION

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32).

NAME AND OFFICIAL TITLE *(Please type or print)*	SIGNATURE	DATE SIGNED
C.C. Parsons, District Manager	CC Parsons	9-17-92

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

JUL 15 1992

RECEIVED
JUL 17 1992
DIVISION OF
OIL GAS & MINING

Ref: 8WM-DW

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. C. C. Parsons
District Manager
ENRON Oil & Gas Company
P. O. Box 250
Big Piney, WY 83113

RE: UNDERGROUND INJECTION CONTROL (UIC)
Draft Permit for the
Natural Buttes Unit No. 21-20B
EPA Permit No. UT2623-03708
Uintah County, Utah

Dear Mr. Parsons:

Enclosed is a Draft Underground Injection Permit for the proposed salt water disposal well, Natural Buttes No. 21-20B SWD. A Statement of Basis, which discusses development of the permit, is also included.

A notice should appear soon in the Vernal, Utah, VERNAL EXPRESS, notifying the public of their opportunity to comment. A notice of our intent to issue a permit has also been sent to the Uintah & Ouray Indian Agency, the Bureau of Land Management, Utah Division of Oil, Gas, and Mining, and other interested lease operators/owners. The public comment period on this action will run for thirty (30) days from the date of publication. You may call Ms. Daniela Thigpen, at (303) 293-1421, to obtain the exact deadline for public comments.

Please be aware that a final permit decision will not be made until after the public comment period closes. Before a final permit decision will be made, all public comments will be taken into consideration. If any substantial comments are received or if any substantial changes are to be made from the draft permit to the final permit, it will be necessary to delay the effective date of the final permit action for an additional thirty (30) days. This delay is required by Section 124.15(b) in order to allow for a potential appeal of the final decision.

The enclosed permit is only a **"DRAFT"** version of the proposed final permit. It is a "sample" of what the final permit contains. Although the text on page four (4), paragraph two (2), of the "Draft" permit says you are authorized to begin injection operations, this version of the permit is NOT official. It is being sent to you so that you may have a chance to comment.

If you have any questions on the draft permit, please call Emmett Schmitz at (303) 293-1436. Please send written comments to the **ATTENTION: EMMETT SCHMITZ** citing **MAIL CODE: 8WM-DW** very prominently.

Sincerely,

Max H. Dodson

Max H. Dodson, Director
Water Management Division

Enclosures: Draft Permit
Draft Statement of Basis
Public Notice

cc: w/enclosures: Mr. Ferron Secakuku
Energy & Mineral Resource Dep't.
Uintah & Ouray Indian Agency
P. O. Box 70
Fort Duchesne, UT 84026

Mr. Gil Hunt
Utah Division of Oil, Gas, and Mining
3 Triad Center, #350
355 West North Temple
Salt Lake City, UT 84180-1203

Mr. Jerry Kenzka
Vernal District
Bureau of Land Management
170 South 300 East
Vernal, UT 84078

Mr. Charles Cameron
Uinta and Indian Agency
Bureau of Indian Affairs
Ft. Duchesne, UT 84026

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

PUBLIC NOTICE
INTENT TO ISSUE AN UNDERGROUND INJECTION CONTROL PERMIT
TO
ENRON OIL & GAS COMPANY

PURPOSE OF PUBLIC NOTICE

The purpose of this notice is to solicit public comment on the proposal by the Region VIII Office of the U. S. Environmental Protection Agency (EPA) to issue a permit to inject fluids underground via a Class II disposal well, the Natural Buttes Unit No. 21-20B SWD, NE 1/4 NE 1/4 Section 20 - T9S - R20E, Uintah County, Utah.

BACKGROUND

EPA Region VIII is currently reviewing an application for an Underground Injection Control Permit from ENRON Oil & Gas Company, regarding Wasatch and Green River Formations salt water disposal operations. The injection fluid is salt water produced in conjunction with the extraction of natural gas from ENRON Oil & Gas Company owned and operated wells in the Natural Buttes Unit.

The EPA has made a preliminary determination that all underground sources of drinking water (USDW) will be protected. Therefore, EPA is hereby serving notice of intent to issue a permit for the proposed underground injection activities, to ENRON Oil & Gas Company.

PUBLIC COMMENTS

All data submitted by the applicant, as well as the draft permit prepared by EPA, are contained in the administrative record for ENRON Oil & Gas Company. This information is available for public inspection at these locations from 9:00 a.m. to 5:00 p.m., or by contacting the following office:

Environmental Protection Agency
Region VIII, 8WM-DW
UIC Implementation Section
Attn: Emmett R. Schmitz
999 18th Street, Suite 500
Denver, Colorado 80202-2466
Telephone (303) 293-1436

Public comments are encouraged and will be accepted, in writing, at the Denver Office for a period of thirty (30) days after publication of this notice. A request for a public hearing should be made in writing and should state the nature of the issues proposed to be raised at the hearing. A PUBLIC HEARING WILL BE HELD ONLY IF SIGNIFICANT INTEREST IS SHOWN.

FINAL PERMIT DECISION AND APPEAL PROCESS

After the close of the public comment period, EPA will issue a final permit decision, and will notify all commenters regarding this decision. The final decision may be to: issue; deny; modify; or revoke and reissue the draft permit. The final decision shall become effective thirty (30) days after the final decision is issued, unless no commenters requested a change in the draft permit, in which case the permit shall become effective immediately upon issuance.

Within thirty (30) days after a final permit decision has been issued, any person who filed comments on the draft permit or participated in a public hearing, may petition the Administrator to review the permit decision. Commenters are referred to 40 CFR Sections 124.15 through 124.20 for procedural requirements of the appeal process.

JUL 15 1992

Date of Publication

Max H. Dodson, Director
Water Management Division

RECEIVED
JUL 17 1992
DIVISION OF
OIL GAS & MINING

DRAFT STATEMENT OF BASIS
NATURAL BUTTES UNIT (NBU) 21-20B SWD
UINTAH COUNTY, UTAH

EPA PERMIT NO. UT2623-03708

CONTACT: Emmett R. Schmitz
U. S. Environmental Protection Agency
UIC Implementation Section, 8WM-DW
999 18th Street, Suite 500
Denver, Colorado 80202-2466
Telephone: (303) 293-1436

DESCRIPTION OF FACILITY AND BACKGROUND INFORMATION:

On April 10, 1992, ENRON Oil & Gas Company made application for an underground injection control permit for the disposal of produced Green River and Wasatch Formations waters from "numerous gas and oil wells in Townships 8, 9 & 10 South, Ranges 19, 20, 21 and 22 East, Uintah Co., Utah." All sources of water are reported to be from permittee operated wells. The NBU 21-20B SWD (NE NE Section 20 - T9S - R20E) is not a commercial salt water disposal well. A water analysis, included in the permit application, describes the Green River Formation disposal water as 42,623 mg/l total dissolved solids (TDS). The TDS of the Wasatch Formation produced water is analyzed at 25,721 mg/l. The total dissolved solids (TDS) content of the Green River "H" sand disposal zone is, by analysis, 20,500 mg/l.

ENRON Oil & Gas Company requested a maximum surface injection pressure of 1400 pounds per square inch gauge (psig). The Environmental Protection Agency (EPA) will initially allow only a maximum surface injection pressure of 600 psig.

ENRON Oil & Gas Company has submitted all required information and data necessary for permit issuance in accordance with 40 CFR Parts 144, 146 and 147, and a draft permit has been prepared. The permit will be issued for the operating life of the salt water disposal well, unless the permit is terminated for reasonable cause (40 CFR 144.39, 144.40 and 144.41). However, the permit will be reviewed every five years.

ENRON Oil & Gas Company has not conducted a mechanical integrity test (MIT) on the NBU 21-20B SWD. <u>An MIT shall be run as one condition for issuance of the Final permit</u>.

This Draft Statement of Basis gives the derivation of the site-specific permit conditions and reasons for them. The referenced sections and conditions correspond to the sections and conditions in Draft Permit UT2623-03708. The general permit conditions for which the content is mandatory and not subject to site-specific differences (based on 40 CFR Parts 144, 146 and 147), are not included in the discussion.

PART II, Section A WELL CONSTRUCTION REQUIREMENTS

<u>Casing and Cementing</u> (Condition 1)

Casing and cementing details were submitted with the permit application. For the proposed disposal well, existing construction is as follows:

(1) Surface casing (9-5/8 inch) is set in a 12-1/4 inch diameter hole to a depth of 196 feet kelly bushing (KB). The surface casing is cemented to the surface.

(2) A 4-1/2 inch longstring is set in a 7-7/8 inch hole to a depth of 7025 feet KB. Total depth is 7025 feet KB. Top of cement (TOC), by a Cement Bond Log (CBL), is 1180 feet KB. However, by calculation, the long string cement should have been circulated to the surface.

Originally, the permittee perforated the gross Wasatch Formation intervals, 6592 - 6916 feet and 6092 - 6130 feet. Prior to natural gas evaluation of Green River "H" sand perforations (3802 - 3825 feet), a "bridge plug" was set at 6200 feet, and a cast iron bridge plug was set at 5100 feet.

The entire Green River Formation is composed of interbedded thick impervious confining shales, and thinner confining limestone and siltstone, with intercalated sequences of porous-permeable sand. The Green River "H" sand disposal interval (3802 - 3825 feet KB) is effectively enclosed by shale, i.e., 3754 - 3798 feet and 3826 - 3850 feet. A Compensated Densilog shows the Green River "H" sand to be 28 feet thick. The proposed disposal interval, 3802 - 3825 feet) is located 3,600 feet below the base of the mapped interval of moderately saline waters, i.e., 3,000 to 10,000 mg/l (BASE OF MODERATELY SALINE GROUND WATER IN THE UINTA BASIN, UTAH). The base of the last USDW (Uinta Formation with State of Utah reported total dissolved solids less than 10,000 mg/l) is 200 feet from the surface, and four (4) feet below the base of the surface casing. The analyzed "swab sample" TDS of 42,623 mg/l for the proposed disposal zone precludes an Aquifer Exemption for the Green River "H" sand. This disposal facility will be adequately constructed to ensure no disposal fluid migration out of the authorized "H" sand interval.

The Uinta Formation extends from the surface to a depth of 1704 feet. The Green River Formation extends from 1704 feet to 5210 feet. The top of the Wasatch Formation occurs at 5210 feet. Total depth is 7025 feet in the Wasatch Formation.

Tubing and Packer Specifications (Condition 2)

The tubing information (2-3/8 inch) submitted by the applicant is incorporated into the permit and shall be binding on the permittee. A 4-1/2 inch LOK-SET packer will be set at an approximate depth of 3750 feet KB, which is less than 100 feet above the top perforation (3802 feet KB).

Monitoring Devices (Condition 4)

For the purposes of taking tubing and tubing/longstring casing annulus pressure measurements, the EPA is requiring that the permittee install 1/2-inch fittings with cut-off valves at the well head on the tubing, and on the tubing/casing annulus.

EPA is further requiring the permittee to install a sampling tap on the line to the disposal well and a flow meter that will be used to measure cumulative volumes of injected fluid.

Formation Testing (Condition 3)

Prior to commencing injection, the Green River "H" sand pore pressure will be determined by measuring and reporting the static fluid level; the tubing/casing annulus will be tested for mechanical integrity at a pressure of at least 300 psig. Results of the mechanical integrity test (MIT) and the recompletion procedures will be reported on the Well Rework Record (Form 7520-12 in Appendix B). Additional formation logging/testing required within six (6) months of authorization to inject include a valid step-rate test (SRT) to determine the Green River "H" disposal zone fracture pressure.

PART II, Section B CORRECTIVE ACTION

The operator is not required to take any corrective action on the one (1) plugged and abandoned gas well in the 1/4-mile area of review (AOR) before the effective date of this permit. The Ute Trail No. 2 (SW NE Section 20 - T9S - R20E), is the only oil and/or gas location within the AOR, and the Ute Trail No. 2 is constructed, and plugged and abandoned, in such a manner as to preclude any contamination from the NBU 21-20B.

PART II, Section C WELL OPERATION

Prior to Commencing Injection (Condition 1)

Injection will not be allowed to commence until the permittee has submitted a Well Rework Record (EPA Form 7520-12); the disposal zone pore pressure has been determined; the well has successfully passed an MIT following test guidelines discussed in the permit.

Mechanical Integrity (Condition 2)

A tubing/casing annulus pressure test must be repeated at least once every five (5) years to demonstrate continued tubing, packer, and casing integrity.

Injection Interval (Condition 3)

Fluid disposal will be limited to the Green River "H" sand interval 3802 - 3825 feet KB.

Injection Pressure Limitation (Condition 4)

The permittee shall limit the maximum surface injection pressure to 600 psig. Permit provisions have been made that allow the operator to request an increase in the injection pressure.

The permittee submitted a January 25, 1992 step-rate test (SRT) which identifies an instantaneous shut-in pressure of 600 psig. This is the maximum surface injection pressure necessary to hold open any fractures for water injection, before creating any new fractures-out-of-zone. A fracture gradient of 0.5973 psi/ft can be calculated:

$$Pmax = (Fg - 0.433Sg)d$$
$$Fg = Pmax/d + 0.433\ Sg$$

Pmax = Maximum surface injection pressure: 600 psig
d = Depth to top perforation: 3802 feet
0.433 = weight of fresh water, as psi/ft
Sg = Specific gravity of injected water: 1.015

$$Fg = 600/3802 + (0.433)(1.015) = 0.5973\ psi/ft$$

A calculated fracture gradient of 0.5973 psi/ft for the Green River Formation is consistent with fracture gradients obtained recently from other Green River step-rate tests.

Injection Volume Limitation (Condition 5)

The daily injection volume rate will not be limited, but in no case shall the injection pressure exceed that listed in Part II, Section C, (Condition 4), above.

There shall be no limit on the cumulative number of barrels of water that may be injected into the Green River "H" sand.

PART II, Section D MONITORING, RECORD KEEPING, AND REPORTING OF RESULTS

Injection Well Monitoring Program (Condition 1)

The permittee is required to monitor water quality of the injected fluids on an annual basis. A water sample of injected fluids shall be analyzed for total dissolved solids, pH, specific conductivity, and specific gravity. Any time there is a change in the source of injection fluid, a new water quality analysis is also required. This analysis is required to be reported to EPA annually. In addition, weekly observations of flow rate, cumulative volume, injection pressure, and annulus pressure will be made. At least one observation each for flow rate, injection pressure, annulus pressure, and cumulative volume will be recorded on a monthly basis. This record is required to be reported to EPA annually.

The permittee shall maintain copies (or originals) of all pertinent records at the office of ENRON Oil & Gas Company, Big Piney, Wyoming.

PART II, Section E PLUGGING AND ABANDONMENT

Plugging and Abandonment Plan (Condition 2)

The plugging and abandonment plan (Appendix C of the Permit) consists of two (2) plugs with the following specifications. This plan has been reviewed and approved by the EPA, with a slight modification of Plug No. 1 by the EPA.

Plug #1 - Set a cement plug from 3700 feet to 3850 feet squeezing off Green River "H" sand perforations 3802 - 3825 feet.

Plug #2 - Set a cement plug inside of the 4-1/2 inch longstring, and the annulus between the 4-1/2 longstring X 9-5/8 inch surface casing from surface to 200 feet.

PART II, Section F FINANCIAL RESPONSIBILITY

Demonstration of Financial Responsibility (Condition 1)

ENRON Oil & Gas Company has submitted a Form 10-K, dated December 31, 1991, that has been reviewed and approved by the EPA.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

UNDERGROUND INJECTION CONTROL PROGRAM

Draft Permit

Class II Salt Water Disposal Well

Permit No. UT2623-03708

Well Name: Natural Buttes Unit (NBU) 21-20B SWD

Field Name: Natural Buttes

County & State: Uintah County, Utah

issued to:

ENRON Oil & Gas Company
Big Piney, Wyoming

Date Prepared: May 1992

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PART I. AUTHORIZATION TO INJECT

Pursuant to the Underground Injection Control Regulations of the U. S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations, Parts 124, 144, 146, and 147,

ENRON Oil & Gas Company
P. O. Box 250
Big Piney, Wyoming 83113

is hereby authorized to convert a Wasatch Formation shut-in gas well to a Class II salt water disposal well, which well will be known as the Natural Buttes Unit 21-20B SWD (NBU 21-20B SWD), located in the NE 1/4 of the NE 1/4 (1037 feet from the north line and 1033 feet from the east line) of Section 20, Township 9 South, Range 20 East, in Uintah County, Utah. Injection shall be for the purpose of disposing of ENRON produced water from the Green River and Wasatch Formations, Natural Buttes Unit, in accordance with conditions set forth herein. Produced water will be injected into the Green River Formation "H" sand. <u>If the well is not converted within one (1) year from the effective date of this permit, the well shall be plugged and abandoned according to permit Condition Part II, Section A. 6</u>.

This document serves as authorization to begin injection activities and also serves as a permit for the well. "Prior to Commencing Injection" requirements are set forth in Part II, Section C. 1. of this permit.

All conditions set forth herein refer to Title 40 Parts 124, 144, 146, and 147 of the Code of Federal Regulations (CFR) and are regulations that are in effect on the date that this permit becomes effective.

This permit consists of a total of 32 pages and includes all items listed in the Table of Contents. Further, it is based upon representations made by the permittee and on other information contained in the administrative record.

This permit and the authorization to inject are issued for the operating life of the well, unless terminated. The permit will be reviewed by EPA at least every five (5) years to determine whether action under 40 CFR 144.36 (a) is warranted. The permit will expire upon delegation of primary enforcement responsibility for the UIC Program to the Uintah and Ouray Indian Agency, unless that Agency has both adequate authority, and chooses, to adopt and enforce this permit as an Agency permit.

Issued this ______ day of ________________, 1992.

This permit shall become effective __________________________.

DRAFT

* Max H. Dodson, Director
Water Management Division

NOTE: The person holding this title is referred to as the "Director" throughout this permit.

PART II. SPECIFIC PERMIT CONDITIONS

A. WELL CONVERSION REQUIREMENTS

1. Casing and Cementing. The proposed conversion details submitted with the application are hereby incorporated into this permit as Appendix A, and shall be binding on the permittee. Existing cement bonds between the wellbore and casing are as follows:

(1) 9-5/8 inch surface casing is set in a 12-1/4 inch diameter hole to a depth of 196 feet kelly bushing (KB). Surface casing is cemented to the surface.

(2) A 4-1/2 inch longstring is set in a 7-7/8 inch hole to a depth of 7025 feet KB. Total depth is 7025 feet KB. Top of cement (TOC), by a cement bond log (CBL), is 1180 feet KB. However, by calculation, this cement should have been circulated to the surface.

(3) Originally the permittee perforated the Wasatch Formation intervals 6914 - 6916 feet, 6907 - 6909 feet, 6592 - 6594 feet, 6128 - 6130 feet, 6111 - 6113 feet, and 6092 - 6094 feet for natural gas evaluation. Prior to perforating the Green River "H" sand (3802 - 3825 feet) for natural gas evaluation, ENRON set a retrievable bridge plug at 6200 feet, and a cast iron bridge plug (CIBP) at 5100 feet.

The confining zone above the proposed Green River "H" sand perforations (3802 - 3825 feet KB) is composed of several hundred feet of impervious shale, limestone and siltstone. Similar thick Green River Formation lithology is present below the proposed disposal zone. A Compensated Densilog shows the Green River "H" sand to be thirty (30) feet thick. The disposal interval occurs 3,600 feet below the base of the mapped interval of moderately saline waters, i.e., 3,000 to 10,000 mg/l. The analyzed "swab sample" total dissolved solids (TDS) content of 42,623 mg/l, for the proposed disposal zone, precludes an Aquifer Exemption for the Green River "H" sand.

2. Tubing and Packer Specifications. A tubing of two and three-eighths (2-3/8) inches diameter will be utilized. A 4-1/2 inch LOK-SET packer will be set at an approximate depth of 3750 feet, which is less than 100 feet above the top perforation (3802 feet).

3. Monitoring Devices. The operator shall provide and maintain in good operating condition:

(a) a tap on the suction line for the purpose of obtaining representative samples of the injection fluids;

(b) two (2), one-half (1/2) inch Female Iron Pipe (FIP) fittings, isolated by plug or globe valves, and located: 1) at the wellhead on the tubing; and 2) on the tubing/casing annulus, and positioned to allow attachment of 1/2 inch Male Iron Pipe (MIP) gauges;

(c) pressure gauges attached to the FIP fittings of the tubing/casing annulus and tubing to allow for monitoring of the annulus and injection fluid pressures shall not be required due to extreme winter temperatures that freeze the gauges. The operator shall always have in his possession calibrated gauges for the use of their field personnel to monitor tubing injection pressure and tubing/casing annulus pressure. The calibrated gauges shall be designed to operate at a certified deviation accuracy of approximately five (5) percent, throughout the range of anticipated injection pressures; and

(d) a non-resettable flow meter with cumulative volume recorder that is certified for at least ninety-five (95) percent accuracy, throughout the range of injection rates allowed by the permit.

4. Proposed Changes and Workovers. The permittee shall give advance notice to the Director, as soon as possible, of any planned physical alterations or additions to the permitted well. Major alterations or workovers of the permitted well shall meet all conditions as set forth in this permit. A major alteration/workover shall be considered any work performed, which affects casing, packer(s), or tubing.

A demonstration of mechanical integrity shall be performed within thirty (30) days of completion of any workover and/or alterations, and prior to resuming injection activities in accordance with Section C. 2.

The permittee shall provide all records of well workovers, logging, or other test data to EPA within sixty (60) days of completion of the activity. Appendix B contains samples of the appropriate reporting forms.

5. Formation Testing. Prior to commencing injection, the Green river "H" sand pore pressure will be determined by measuring and reporting the static fluid level; the tubing/casing annulus will be tested for mechanical integrity at a pressure of at least 300 psig. Results of the mechanical integrity test (MIT) and the recompletion procedures will be reported on the Well Rework Record (EPA Form 7520-12 in Appendix B). Additional testing within a six (6) month period after authorization to inject will include a valid step-rate test (SRT) to determine the Green River "H" sand formation fracture pressure.

6. Postponement of Conversion. If the well is not converted/completed for disposal service within one (1) year from the effective date of this permit, the well will be plugged and abandoned in accordance with the Plugging and Abandonment Plan (Appendix C), unless the permittee requests an extension. The written request shall be made to the Director, and shall state the reasons for the delay in conversion/construction. The extension under this section may not exceed one (1) year.

B. CORRECTIVE ACTION

There is one (1) plugged and abandoned former Wasatch Formation gas well, the Ute Trail No. 2, SW/4 NE/4 Section 20 - T9S - R20E, within a one-quarter (1/4) mile radius Area of Review (AOR) of the proposed salt water disposal well. This well has a total depth below the Green River Formation "H" disposal zone (3802 - 3825 feet), but the Ute Trail No. 2 is effectively plugged and abandoned to preclude any underground source of drinking water (USDW) endangerment. No corrective action is required.

C. WELL OPERATION

1. Prior to Commencing Injection. Disposal operations may not commence until the permittee has complied with both (a) and (b), as follows:

(a) All conversion/construction is complete; logging and/or testing requirements have been fulfilled, and the permittee has submitted a Well Rework Record (EPA Form 7520-12 in Appendix B)

(i) The Director has inspected or otherwise reviewed the newly converted disposal well and he has notified the operator that the well is in compliance with the conditions of the permit; or

(ii) The Permittee has not received notice from the Director of his or her intent to inspect or otherwise review the new disposal well within thirteen (13) days of the date the Director has received the Well Rework Record, paragraph (a) above, in which case prior inspection or review is waived and the permittee may commence injection.

(b) The permittee demonstrates that the well has <u>mechanical integrity</u> in accordance with 40 CFR 146.8 and Part II, Section C.2., below, and has received notice from the Director that such a demonstration is satisfactory. The permittee shall notify EPA two (2) weeks prior to conducting this test so that a representative of the EPA may be present to observe the test. Results of the test shall be submitted to the Director as soon as possible, but no later that thirty (30) days after the demonstration.

2. <u>Mechanical Integrity</u>.

(a) <u>Method of Demonstrating Mechanical Integrity</u>. A demonstration of the absence of significant leaks in the casing, tubing, and/or packer must be made by performing a tubing/casing annulus pressure test. This test shall be for a minimum of forty-five (45) minutes at: (1) a pressure of 300 pounds per square inch gauge (psig) measured at the surface, if the well is shut-in; or (2) a pressure differential of 200 psig between the tubing and the tubing/casing annulus, if injection activities are continued during the test. The tubing/casing annulus shall be filled with a non-corrosive fluid (either a non-toxic liquid or the injection liquid) at least twenty-four (24) hours in advance of the test. Pressure values shall be recorded at five-minute intervals. A well passes the mechanical integrity test if there is less than a ten (10) percent decrease or increase in pressure over the forty-five (45) minute period.

(b) <u>Schedule for Demonstration of Mechanical Integrity.</u> A demonstration of mechanical integrity shall be made at regular intervals, no less frequently than once every five (5) years, in accordance with 40 CFR 146.8, unless otherwise modified. The Director may require a demonstration of mechanical integrity, as described in Part II, Section C. 1. (c), at any time during the permitted life of the well.

(c) Loss of Mechanical Integrity. If the well fails to demonstrate mechanical integrity, or a loss of mechanical integrity as defined by 40 CFR 146.8 becomes evident during operation, the permittee shall notify the Director in accordance with Part III, Section E. 10. of this permit. Furthermore, injection activities shall be terminated, and operations shall not be resumed until the permittee has taken actions to restore integrity to the well and EPA gives approval to resume injection.

3. Injection Interval. Injection shall be limited to the Green River Formation "H" sand interval 3802 - 3825 feet KB.

4. Injection Pressure Limitation.

(a) Injection pressure, measured at the surface, shall not exceed an amount that the Director determines is appropriate to ensure that injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USWD.

(b) The exact pressure limit may be increased or decreased by the Director to ensure that the requirements in paragraph (a) are fulfilled. In order to determine an exact pressure limit, the permittee shall conduct a step-rate injection test or other authorized well test(s) that will serve to determine the fracture pressure of the injection zone. Test procedures shall be pre-approved by the Director. The Director will specify in writing, to the permittee, any increase or decrease to the injection pressure based upon the test results and/or other parameters reflecting actual injection operations. Until such time that this demonstration is made, the initial injection pressure, measured at the surface, shall not exceed 600 psig.

5. Injection Volume Limitation. There is no limitation on the number of barrels of water per day (BWPD) that shall be injected into the Green River Formation "H" sand, provided further that in no case shall injection pressure exceed that limit shown in Part II, Section C. 4. of this permit.

6. Injection Fluid Limitation. Injection fluids are limited to those which are brought to the surface in connection with natural gas storage operations, or conventional oil and gas production, and may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection. Fluids shall be further limited to those generated by sources owned or operated by the permittee. The permittee shall provide an annual listing of the sources of injected fluids in accordance with the reporting requirements in Part II, Section D. 4. of this permit.

7. Annular Fluid. The annulus between the tubing and the casing shall be filled with fresh water treated with a corrosion inhibitor, a scale inhibitor, and an oxygen scavenger; or other fluid as approved, in writing, by the Director.

D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Injection Well Monitoring Program. Samples and measurements shall be representative of the monitored activity. The permittee shall utilize the applicable analytical methods described in Table 1 of 40 CFR 136.3, or in Appendix III of 40 CFR Part 261, or in certain circumstances, by other methods that have been approved by the EPA Administrator. Monitoring shall consist of:

(a) Analysis of the disposed fluids, performed:

(i) annually for Total Dissolved Solids, pH, Specific Conductivity, and Specific Gravity from the common facility; however, if injection is maintained from more than one well from each common facility, then only one annual analysis is required for that facility.

(ii) whenever there is a change in the source of disposed fluids. A comprehensive water analysis shall be submitted to the Director within thirty (30) days of any change in injection fluids.

(b) Weekly observations of flow rate, injection pressure and annulus pressure, and cumulative volume. Observation of each shall be recorded monthly.

2) Monitoring Information. Records of any monitoring activity required under this permit shall include:

(a) The date, exact place, the time of sampling or field measurements;

(b) The name of the individual(s) who performed the sampling or measurements;

(c) The exact sampling method(s) used to take samples;

(d) The date(s) laboratory analyses were performed;

(e) The name of the individual(s) who performed the analyses;

(f) The analytical techniques or methods used by laboratory personnel; and

(g) The results of such analyses.

3. Recordkeeping.

(a) The permittee shall retain records concerning:

(i) the nature and composition of all injected fluids until three (3) years after the completion of plugging and abandonment which has been carried out in accordance with the Plugging and Abandonment Plan shown in Appendix C, and is consistent with 40 CFR 146.10.

(ii) all monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation and copies of all reports required by this permit for a period of at least five (5) years from the date of the sample, measurement or report throughout the operating life of the well.

(b) The permittee shall continue to retain such records after the retention period specified in paragraphs (a) (i) and (a) (ii) unless he delivers the records to the Director or obtains written approval from the Director to discard the records.

(c) The Permittee shall maintain copies (or originals) of all pertinent records at the office of ENRON Oil & Gas Company, Big Piney, Wyoming.

4. Reporting of Results. The permittee shall submit an Annual Report, whether injecting or not, to the Director summarizing the results of the monitoring required by Part II, Section D. 1. (a) and (b) of this permit. The permittee shall also include a listing of all sources of the fluids injected during the year identifying the source by either the well name(s), the field name(s), or the facility name(s).

The first Annual Report shall cover the period from the effective date of the permit through December 31 of that year. Subsequent Annual Reports shall cover the period from January 1 through December 31. Annual Reports shall be submitted by February 15 of the following year following data collection. Appendix B contains Form 7520-11 which may be copied and used to submit the Annual Report.

E. PLUGGING AND ABANDONMENT

1. Notice of Plugging and Abandonment. The permittee shall notify the Director forty-five (45) days before abandonment of the well.

2. Plugging and Abandonment Plan. The permittee shall plug and abandon the well as provided in the Plugging and Abandonment Plan, Appendix C. This plan incorporates information supplied by the permittee and may contain a clarification by the EPA. The EPA reserves the right to change the manner in which the well will be plugged if the well is modified during its permitted life or if the well is not made consistent with EPA requirements for construction and mechanical integrity. The Director may require the permittee to update the estimated plugging cost periodically. Such estimates shall be based upon costs which a third party would incur to plug the well according to the plan.

3. Cessation of Injection Activities. After a cessation of operations of two (2) years, the permittee shall plug and abandon the well in accordance with the Plugging and Abandonment Plan, unless the permittee:

(a) has provided notice to the Director; and

(b) has demonstrated that the well will be used in the future; and

(c) has described actions or procedures, satisfactory to the Director, that will be taken to ensure that the well will not endanger underground sources of drinking water during the period of temporary abandonment.

4. Plugging and Abandonment Report. Within sixty (60) days after plugging the well, the permittee shall submit a report on Form 7520-13 to the Director. The report shall be certified as accurate by the person who performed the plugging operation, and the report shall consist of either: (1) a statement that the well was plugged in accordance with the plan; or (2) where actual plugging differed from the plan, a statement that specifies the different procedures followed.

F. FINANCIAL RESPONSIBILITY

1. Demonstration of Financial Responsibility. The permittee is required to maintain continuous financial responsibility and resources to close, plug, and abandon the injection well as provided in the plugging and abandonment plan.

(a) ENRON Oil & Gas Company has submitted a Form 10-K, dated December 31, 1991, that has been reviewed and approved by the EPA.

(b) The permittee may, upon his own initiative and upon written request to EPA, change the method of demonstrating financial responsibility. Any such change must be approved by the Director. A minor permit modification will be made to reflect any change in financial mechanisms, without further opportunity for public comment.

2. Insolvency of Financial Institution. In the event that an alternate demonstration of financial responsibility has been approved under (b) or (c), above, the permittee must submit an alternate demonstration of financial responsibility acceptable to the Director within sixty (60) days after either of the following events occur:

(a) The institution issuing the trust or financial instrument files for bankruptcy; or

(b) The authority of the trustee institution to act as trustee, or the authority of the institution issuing the financial instrument, is suspended or revoked.

3. Cancellation of Demonstration by Financial Institution.

The permittee must submit an alternative demonstration of financial responsibility acceptable to the Director, within sixty (60) days after the institution issuing the trust or financial instrument serves 120-day notice to the EPA of their intent to cancel the trust or financial instrument.

PART III. GENERAL PERMIT CONDITIONS

A. EFFECT OF PERMIT

The permittee is allowed to engage in underground disposal in accordance with the conditions of this permit. The permittee, as authorized by this permit, shall not construct, operate, maintain, convert, plug, abandon, or conduct any other disposal activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR, Part 142 or otherwise adversely affect the health of persons. Any underground disposal activity not authorized in this permit or otherwise authorized by permit or rule is prohibited. Issuance of this permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local law or regulations. Compliance with the terms of this permit does not constitute a defense to any enforcement action brought under the provisions of Section 1431 of the Safe Drinking Water Act (SDWA) or any other law governing protection of public health or the environment for any imminent and substantial endangerment to human health, or the environment, nor does it serve as a shield to the permittee's independent obligation to comply with all UIC regulations.

B. PERMIT ACTIONS

1. Modification, Reissuance, or Termination. The Director may, for cause or upon a request from the permittee, modify, revoke and reissue, or terminate this permit in accordance with 40 CFR Sections 124.5, 144.12, 144.39, and 144.40. Also, the permit is subject to minor modifications for cause as specified in 40 CFR Section 144.41. The filing of a request for a permit modification, revocation and reissuance, or termination or the notification of planned changes or anticipated noncompliance on the part of the permittee does not stay the applicability or enforceability of any permit condition.

2. Conversions. The Director may, for cause or upon a request from the permittee, allow conversion of the well from a Class II salt water disposal well to a non-Class II well. Requests to convert the disposal well from its Class II status to a non-Class II well, such as, a production well, must be made in writing to the Director. Conversion may not proceed until a permit modification indicating the conditions of the proposed conversion is received by the permittee. Conditions of the

modification may include such items as, but is not limited to, approval of the proposed well rework, follow up demonstration of mechanical integrity, and well specific monitoring and reporting following the conversion.

3. Transfers. This permit is not transferrable to any person except after notice is provided to the Director and the requirements of 40 CFR 144.38 are complied with. The Director may require modification, or revocation and reissuance, of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the SDWA.

4. Operator Change of Address. Upon the operator's change of address, notice must be given to the appropriate EPA office at least fifteen (15) days prior to the effective date.

C. SEVERABILITY

The provisions of this permit are severable, and if any provision of this permit or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit shall not be affected thereby.

D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and 40 CFR 144.5, any information submitted to EPA pursuant to this permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2 (Public Information). Claims of confidentiality for the following information will be denied:

- The name and address of the permittee; and
- Information which deals with the existence, absence or level of contaminants in drinking water.

E. GENERAL DUTIES AND REQUIREMENTS

1. Duty to Comply. The permittee shall comply with all conditions of this permit, except to the extent and for the duration such noncompliance is authorized by an emergency permit. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action, permit termination, revocation and reissuance, or modification. Such noncompliance may also be grounds for enforcement action under the Resource Conservation and Recovery Act (RCRA).

2. Penalties for Violations of Permit Conditions. Any person who violates a permit requirement is subject to civil penalties, fines, and other enforcement action under the SDWA and may be subject to such actions pursuant to the RCRA. Any person who willfully violates permit conditions may be subject to criminal prosecution.

3. Need to Halt or Reduce Activity not a Defense. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

4. Duty to Mitigate. The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.

5. Proper Operation and Maintenance. The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit.

6. Duty to Provide Information. The permittee shall furnish the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with the permit. The permittee shall also furnish to the Director, upon request, copies of records required to be kept by this permit.

7. Inspection and Entry. The permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

(a) Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this permit;

(b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

(c) Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and

(d) Sample or monitor, at reasonable times, for the purpose of assuring permit compliance or as otherwise authorized by the SDWA any substances or parameters at any location.

8. Records of Permit Application. The permittee shall maintain records of all data required to complete the permit application and any supplemental information submitted for a period of five (5) years from the effective date of this permit. This period may be extended by request of the Director at any time.

9. Signatory Requirements. All reports or other information requested by the Director shall be signed and certified according to 40 CFR 144.32.

10. Reporting of Noncompliance.

(a) Anticipated Noncompliance. The permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

(b) Compliance Schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted no later than thirty (30) days following each schedule date.

(c) <u>Twenty-four Hour Reporting</u>.

(i) The permittee shall report to the Director any noncompliance which may endanger health or the environment. Information shall be provided orally within twenty-four (24) hours from the time the permittee becomes aware of the circumstances by telephoning EPA at (303) 293-1436 (during normal business hours) or at (303) 293-1788 (for reporting at all other times). The following information shall be included in the verbal report:

(A) Any monitoring or other information which indicates that any contaminant may cause endangerment to an underground source of drinking water.

(B) Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between underground sources of drinking water.

(ii) A written submission shall also be provided within five (5) days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

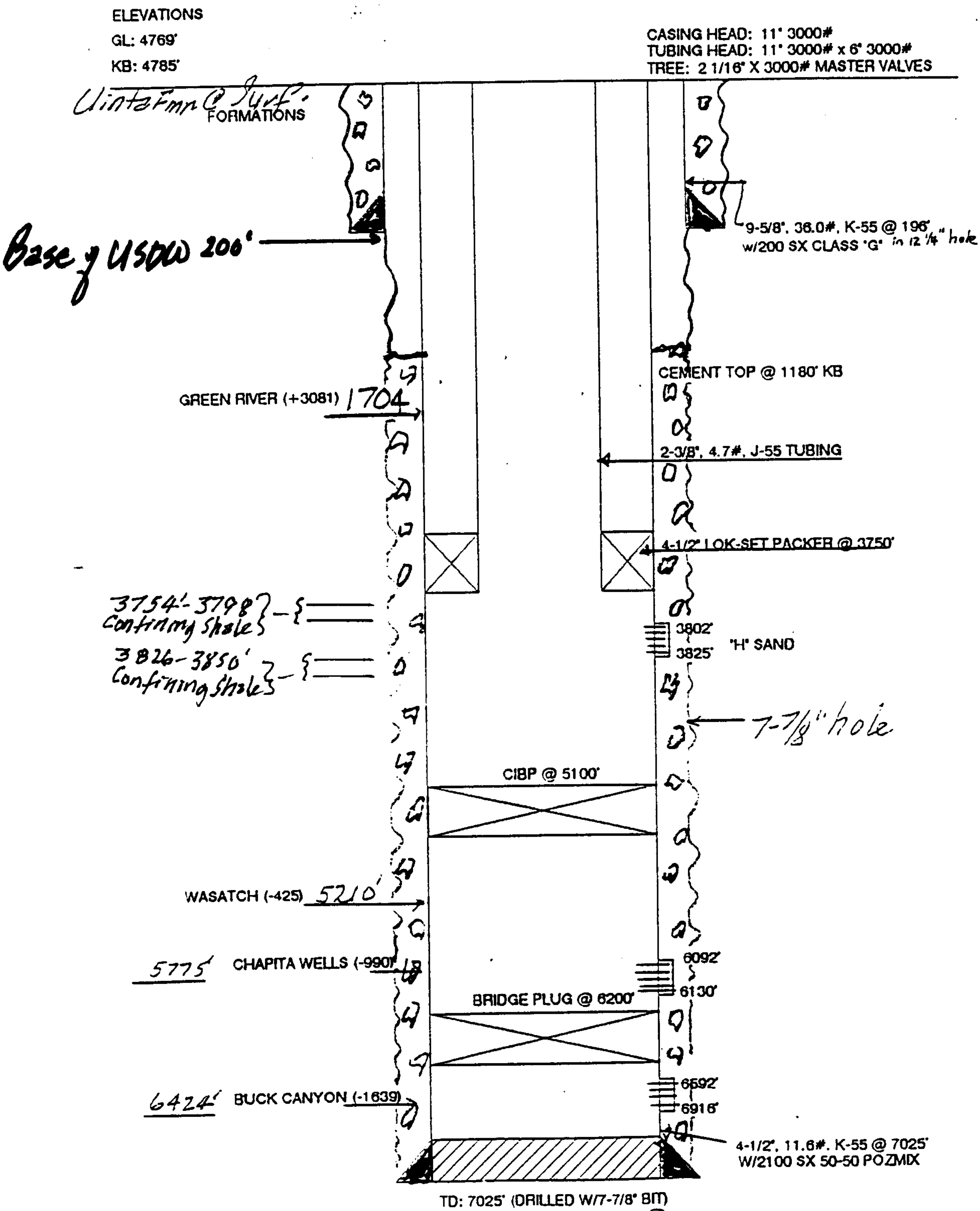
(d) <u>Other Noncompliance</u>. The permittee shall report all other instances of noncompliance not otherwise reported at the time monitoring reports are submitted. The reports shall contain the information listed in Part III, Section E. 10. (c) (ii) of this permit.

(e) Other Information. Where the permittee becomes aware that any relevant facts were not submitted in the permit application, or incorrect information was submitted in a permit application or in any report to the Director, the permittee shall submit such correct facts or information within two (2) weeks of the time such information becomes known.

APPENDIX A (CONVERSION DETAILS)

PROPOSED WELL CONVERSION - SCHEMATIC DIAGRAM

NATURAL BUTTES UNIT 21-20 B
NENE, SECTION 20, T9S, R20E
UINTAH COUNTY, UTAH



APPENDIX B (REPORTING FORMS)

1. EPA Form 7520- 7: APPLICATION TO TRANSFER PERMIT
2. EPA Form 7520-10: COMPLETION REPORT FOR BRINE DISPOSAL WELL
3. EPA Form 7520-11: ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT
4. EPA Form 7520-12: WELL REWORK RECORD
5. EPA Form 7520-13: PLUGGING RECORD

Form Approved. OMB No. 2000-0042. Approval expires 9-30-86

EPA

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, DC 20460

APPLICATION TO TRANSFER PERMIT

NAME AND ADDRESS OF EXISTING PERMITTEE	NAME AND ADDRESS OF SURFACE OWNER

LOCATE WELL AND OUTLINE UNIT ON SECTION PLAT — 640 ACRES

N

W E

S

STATE	COUNTY	PERMIT NUMBER

SURFACE LOCATION DESCRIPTION

¼ OF ¼ OF ¼ SECTION TOWNSHIP RANGE

LOCATE WELL IN TWO DIRECTIONS FROM NEAREST LINES OF QUARTER SECTION AND DRILLING UNIT

Surface
Location ____ ft. from (N/S) ____ Line of quarter section

and ____ ft. from (E/W) ____ Line of quarter section

WELL ACTIVITY	WELL STATUS	TYPE OF PERMIT
☐ Class I	☐ Operating	☐ Individual
☐ Class II	☐ Modification/Conversion	☐ Area
☐ Brine Disposal	☐ Proposed	Number of Wells ____
☐ Enhanced Recovery		
☐ Hydrocarbon Storage		
☐ Class III		
☐ Other		

Lease Name Well Number

NAME(S) AND ADDRESS(ES) OF NEW OWNER(S)	NAME AND ADDRESS OF NEW OPERATOR

Attach to this application a written agreement between the existing and new permittee containing a specific date for transfer of permit responsibility, coverage, and liability between them.

The new permittee must show evidence of financial responsibility by the submission of surety bond, or other adequate assurance, such as financial statements or other materials acceptable to the director.

CERTIFICATION

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

NAME AND OFFICIAL TITLE *(Please type or print)*	SIGNATURE	DATE SIGNED

EPA Form 7520-7 (2-84)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, DC 20460

EPA

COMPLETION REPORT FOR BRINE DISPOSAL, HYDROCARBON STORAGE, OR ENHANCED RECOVERY WELL

Form Approved
OMB No. 2040-0042
Approval expires 9-30-86

NAME AND ADDRESS OF EXISTING PERMITTEE	NAME AND ADDRESS OF SURFACE OWNER

LOCATE WELL AND OUTLINE UNIT ON SECTION PLAT — 640 ACRES

N

W E

S

STATE	COUNTY	PERMIT NUMBER

SURFACE LOCATION DESCRIPTION

¼ OF ¼ OF ¼ SECTION TOWNSHIP RANGE

LOCATE WELL IN TWO DIRECTIONS FROM NEAREST LINES OF QUARTER SECTION AND DRILLING UNIT

Surface
Location ____ ft. from (N/S) ____ Line of quarter section

and ____ ft. from (E/W) ____ Line of quarter section

WELL ACTIVITY	TYPE OF PERMIT	
☐ Brine Disposal	☐ Individual	Estimated Fracture Pressure
☐ Enhanced Recovery	☐ Area	of Injection Zone
☐ Hydrocarbon Storage	Number of Wells ____	

Anticipated Daily Injection Volume (Bbls)		Injection Interval	
Average	Maximum	Feet	to Feet

Anticipated Daily Injection Pressure (PSI)		Depth to Bottom of Lowermost Freshwater Formation (Feet)
Average	Maximum	

Type of Injection Fluid *(Check the appropriate block(s))*

☐ Salt Water ☐ Brackish Water ☐ Fresh Water
☐ Liquid Hydrocarbon ☐ Other

Lease Name	Well Number

Name of Injection Zone

Date Drilling Began	Date Well Completed

Permeability of Injection Zone

Date Drilling Completed

Porosity of Injection Zone

CASING AND TUBING			CEMENT		HOLE	
OD Size	Wt/Ft — Grade — New or Used	Depth	Sacks	Class	Depth	Bit Diameter

INJECTION ZONE STIMULATION		WIRE LINE LOGS, LIST EACH TYPE	
Interval Treated	Materials and Amount Used	Log Types	Logged Intervals

Complete Attachments A — E listed on the reverse.

CERTIFICATION

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32).

NAME AND OFFICIAL TITLE *(Please type or print)*		DATE SIGNED

Form Approved. OMB No. 2040-0042. Expires 9-30-91

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, DC 20460

EPA

ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT

NAME AND ADDRESS OF EXISTING PERMITTEE	NAME AND ADDRESS OF SURFACE OWNER

LOCATE WELL AND OUTLINE UNIT ON SECTION PLAT — 640 ACRES

N

W E

S

STATE	COUNTY	PERMIT NUMBER

SURFACE LOCATION DESCRIPTION

¼ OF ¼ OF ¼ SECTION TOWNSHIP RANGE

LOCATE WELL IN TWO DIRECTIONS FROM NEAREST LINES OF QUARTER SECTION AND DRILLING UNIT

Surface
Location ____ ft. from (N/S) ____ Line of quarter section

and ____ ft. from (E/W) ____ Line of quarter section

WELL ACTIVITY	TYPE OF PERMIT
☐ Brine Disposal	☐ Individual
☐ Enhanced Recovery	☐ Area
☐ Hydrocarbon Storage	Number of Wells ____

Lease Name Well Number

	INJECTION PRESSURE		TOTAL VOLUME INJECTED		TUBING — CASING ANNULUS PRESSURE (OPTIONAL MONITORING)	
MONTH YEAR	AVERAGE PSIG	MAXIMUM PSIG	BBL	MCF	MINIMUM PSIG	MAXIMUM PSIG

CERTIFICATION

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32).

NAME AND OFFICIAL TITLE *(Please type or print)*	SIGNATURE	DATE SIGNED

Form App[illegible]d. OMB No. 2000-0042. Approval expires 9-30-86

EPA

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, DC 20460

WELL REWORK RECORD

NAME AND ADDRESS OF PERMITTEE	NAME AND ADDRESS OF CONTRACTOR

LOCATE WELL AND OUTLINE UNIT ON SECTION PLAT — 640 ACRES

N / W / E / S

STATE	COUNTY	PERMIT NUMBER

SURFACE LOCATION DESCRIPTION

¼ OF ¼ OF ¼ SECTION TOWNSHIP RANGE

LOCATE WELL IN TWO DIRECTIONS FROM NEAREST LINES OF QUARTER SECTION AND DRILLING UNIT

Surface Location ____ ft. from (N/S) ____ Line of quarter section

and ____ ft. from (E/W) ____ Line of quarter section

WELL ACTIVITY		TYPE OF PERMIT
☐ Brine Disposal ☐ Enhanced Recovery ☐ Hydrocarbon Storage	Total Depth Before Rework	☐ Individual ☐ Area Number of Wells ____
	Total Depth After Rework	
Lease Name	Date Rework Commenced	Well Number
	Date Rework Completed	

WELL CASING RECORD — BEFORE REWORK

Casing		Cement		Perforations		Acid or Fracture Treatment Record
Size	Depth	Sacks	Type	From	To	

WELL CASING RECORD — AFTER REWORK *(Indicate Additions and Changes Only)*

Casing		Cement		Perforations		Acid or Fracture Treatment Record
Size	Depth	Sacks	Type	From	To	

DESCRIBE REWORK OPERATIONS IN DETAIL USE ADDITIONAL SHEETS IF NECESSARY	WIRE LINE LOGS, LIST EACH TYPE	
	Log Types	Logged Intervals

CERTIFICATION

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32).

NAME AND OFFICIAL TITLE *(Please type or print)*	SIGNATURE	DATE SIGNED

Form Appr OMB No. 2000-0042 Approval expires 9-30-91

EPA

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, DC 20460

PLUGGING RECORD

NAME AND ADDRESS OF PERMITTEE	NAME AND ADDRESS OF CEMENTING COMPANY

LOCATE WELL AND OUTLINE UNIT ON SECTION PLAT — 640 ACRES

N / W / E / S

STATE	COUNTY	PERMIT NUMBER

SURFACE LOCATION DESCRIPTION

¼ OF ¼ OF ¼ SECTION TOWNSHIP RANGE

LOCATE WELL IN TWO DIRECTIONS FROM NEAREST LINES OF QUARTER SECTION AND DRILLING UNIT

Surface Location ____ ft. from (N/S) ____ Line of quarter section

and ____ ft. from (E/W) ____ Line of quarter section

TYPE OF AUTHORIZATION

- ☐ Individual Permit
- ☐ Area Permit
- ☐ Rule

Number of Wells ____

Lease Name

Describe in detail the manner in which the fluid was placed and the method used in introducing it into the hole

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT(LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE

WELL ACTIVITY

- ☐ CLASS I
- ☐ CLASS II
  - ☐ Brine Disposal
  - ☐ Enhanced Recovery
  - ☐ Hydrocarbon Storage
- ☐ CLASS III

METHOD OF EMPLACEMENT OF CEMENT PLUGS

- ☐ The Balance Method
- ☐ The Dump Bailer Method
- ☐ The Two-Plug Method
- ☐ Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inches)							
Depth to Bottom of Tubing or Drill Pipe (ft.)							
Sacks of Cement To Be Used (each plug)							
Slurry Volume To Be Pumped (cu. ft.)							
Calculated Top of Plug (ft.)							
Measured Top of Plug (if tagged ft.)							
Slurry Wt. (Lb./Gal.)							
Type Cement or Other Material (Class III)							

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS

From	To	From	To

Signature of Cementer or Authorized Representative	Signature of EPA Representative

CERTIFICATION

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations. (REF. 40 CFR 122.22)

NAME AND OFFICIAL TITLE *(Please type or print)*	SIGNATURE	DATE SIGNED

APPENDIX C (PLUGGING & ABANDONMENT PLAN)

Plugging and Abandonment Plan

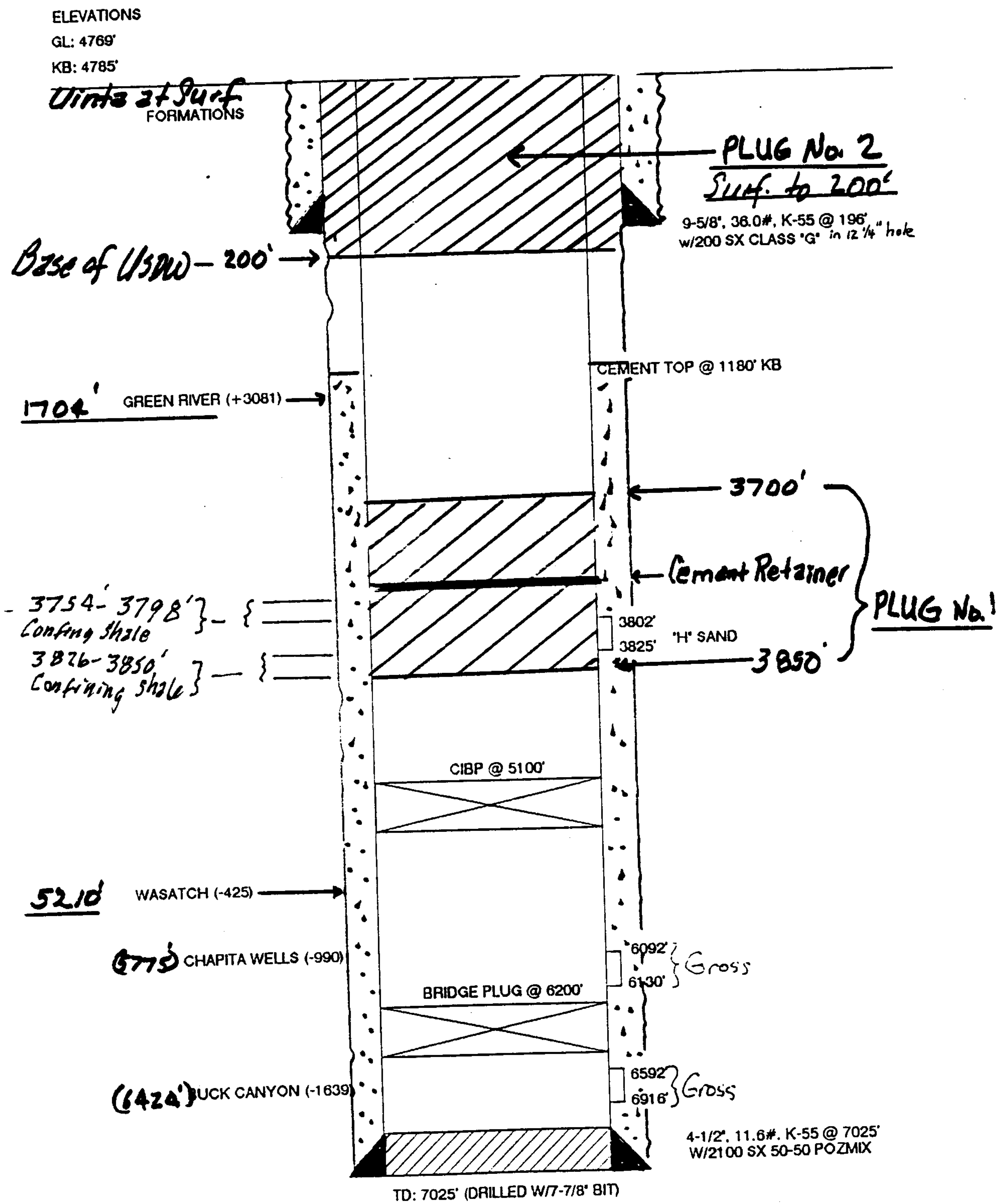
The Plugging and Abandonment Plan, submitted by the applicant, has been revised (Plug No. 1) by the EPA to make the Plan consistent with UIC regulations.

Plug #1 - Set a cement plug 3700 - 3850 feet, with a cement retainer at 3750 feet.

Plug #2 - Set a cement plug 200 feet to the surface. Perforate at 200 feet and squeeze cement to surface in the 4-1/2 inch casing and in the annulus between the 4-1/2 inch casing and the 9-5/8 inch surface casing.

PLUGGING AND ABANDONMENT SCHEMATIC
NATURAL BUTTES UNIT 21-20B SWD

NATURAL BUTTES UNIT 21-20 B
NENE, SECTION 20, T9S, R20E
UINTAH COUNTY, UTAH



INJECTION WELL APPLICATION

REVIEW SUMMARY

Applicant: ENRON OIL AND GAS Well: NATURAL BUTTES 21-20B

Location: section 20 township 09 SOUTH range 20 EAST

API #:43-047-30359 Well Type: disp. X enhanced recov.___

If enhanced recovery has project been approved by the Board ? NA

Lease Type: FEDERAL Surface Ownership: INDIAN

Field: NATURAL BUTTES Unit:________ Indian Country: YES

UIC Form 1: NO Plat: YES Wells in AOR: 12P,3PA,1TA

Logs Available: YES Bond Log: YES

Casing Program: SUFFICIENT

Integrity Test: TO BE RUN AT CONVERSION

Injection Fluid: H20

Geologic Information: GREEN RIVER H INJECTION ZONE, SHALE AND LIMESTON CONFINING BEDS

Analyses of Injection Fluid: YES Formation Fluid: YES Compat. NO

Fracture Gradient Information: YES Parting Pressure: 1680 ESTIMATED

Affidavit of Notice to Owners: YES

Fresh Water Aquifers in Area: SUFACE ALLUVIUM AND UPPER UINTA

Depth Base of Moderately Saline Water: 800

Confining Interval: GREEN RIVER SHALES AND LIMES

Reviewer: D. JARVIS Date: 07-30-92

Comments & Recommendation PROPOSED DISPOSAL INTO GREEN RIVER H SAND, THIS ZONE APPEARS TO BE ABOVE PRODUCING ZONES IN WELLS IN AREA OF REVIEW, WELL IS IN INDIAN COUNTRY AND IS BEING REVIEWED AND PERMITTED BY EPA

FORM 3160-5
(December 1989)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
Budget Bureau No. 1004-0135
Expires September 30, 1990

SUNDRY NOTICE AND REPORTS ON WELLS

Do not use this form for proposals to drill or to deepen or reentry to a different reservoir.
Use "APPLICATION FOR PERMIT --" for such proposals

SUBMIT IN TRIPLICATE

RECEIVED
SEP 2 1 1992
DIVISION OF
OIL GAS & MINING

1. Type of Well
   Oil Well [ ] Gas Well [X] Other [ ]
2. Name of Operator
   ENRON OIL & GAS COMPANY
3. Address and Telephone No.
   P.O. BOX 250, BIG PINEY, WY 83113 (307) 276-3331
4. Location of Well (Footage, Sec., T., R., or Survey Description)
   1037' FNL - 1033' FEL (NE/NE)
   SECTION 20, T9S, R20E

5. Lease Designation and Serial No.
   U 0144869
6. If Indian, Allottee or Tribe Name
   UTE TRIBAL SURFACE
7. If Unit or C.A., Agreement Designation
   NATURAL BUTTES UNIT
8. Well Name and No.
   NATURAL BUTTES UNIT 21-20B
9. API Well No.
   43-047-30359
10. Field and Pool or Exploratory Area
   NATURAL BUTTES/WASATCH
11. County or Parrish, State
   UINTAH, UTAH

12. CHECK APPROPRIATE BOX(s) TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION	
[ ] NOTICE OF INTENT	[ ] ABANDONMENT	[ ] CHANGE OF PLANS
[X] SUBSEQUENT REPORT	[ ] RECOMPLETION	[ ] NEW CONSTRUCTION
[ ] FINAL ABANDONMENT NOTICE	[ ] PLUGGING BACK	[ ] NON-ROUTINE FRACTURING
	[ ] CASING REPAIR	[ ] WATER SHUT-OFF
	[ ] ALTERING CASING	[X] CONVERSION TO INJECTION
	[ ] OTHER	

(Note: Report results of multiple completion on Well Completions or Recompletion Report and Log Form.)

13. Describe Proposed or Completed Operations (Clearly state all pertinent details and give pertinent dates, including estimated date of starting any proposed work if well is directionally drilled give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work).

Enron Oil & Gas Company converted the subject well from shut-in gas well to water disposal well as follows:

1. Set CIBP @ 5100' KB.
2. Perforated the Green River "H" sand @ 3802-25' w/2 SPF.
3. Stimulated with 3,500 gals 15% HCL and 2,000# 16/30 sand.
4. Ran 4-1/2" Baker Model "D" packer on 2-3/8" tubing and set @ 3764' KB with 11,000# tension.
5. Ran static BHP survey: 170 hrs. SIBHP @ 3815' KB, 1638 psig, steady. SITP 230 psig. Casing/tubing annulus pressure tested to 650 psig. Held steady 50 minutes.
6. Mechanical Integrity Test and Step Rate Test is scheduled to be witnessed by the EPA on September 22, 1992.

14. I hereby certify that the foregoing is true and correct

SIGNED Katy Carlson TITLE *Regulatory Analyst* DATE 9-17-92

(This space for Federal or State office use)

APPROVED BY TITLE DATE

CONDITIONS OF APPROVAL, IF ANY:

ENRON
Oil & Gas Company

P.O. Box 250 Big Piney, Wyoming 83113 (307) 276-3331

September 17, 1992

Mr. Gustav Stolz, Jr., P.E.
U.S. Environmental Protection Agency
Denver Place
999 18th Street, Suite 500
Denver, Colorado 80202-2405

RE: UNDERGROUND INJECTION CONTROL
COMPLETION REPORTS
NATURAL BUTTES UNIT 21-20B
NE/NE, SEC. 20, T9S, R20E
UINTAH, UTAH

Dear Mr. Stolz:

Please find attached, the Completion Report, Well Rework Record and U.S. Department of Interior Form 3160-5 for Natural Buttes Unit 21-20B SWD well.

If additional information is required, please contact Jim Schaefer of this office.

Sincerely,

CC Parsons

C.C. Parsons
District Manager

kc

Attachments

cc: State of Utah - Division of Oil, Gas, & Mining
BLM - Vernal District Office
D. Weaver
J. Tigner - 2043
Vernal Office
File

RECEIVED
SEP 21 1992
DIVISION OF
OIL GAS & MINING

ENRON
Oil & Gas Company

P.O. Box 250 Big Piney, Wyoming 83113 (307) 276-3331

January 25, 1993

Mr. Chuck Williams
U.S. Environmental Protection Agency
Region VIII - 8WM-DW
999 18th Street, Suite 500
Denver, Colorado 80202-2466

RE: ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT
NATURAL BUTTES UNIT 21-20B
NE/NE, SEC. 20, T9S, R20E
UINTAH, UTAH

Dear Mr. Williams:

Please find attached, the Annual Disposal/Injection Well Monitoring and water analysis reports for Natural Buttes Unit 21-20B SWD well.

If additional information is required, please contact Jim Schaefer of this office.

Sincerely,

C.C. Parsons

C.C. Parsons
District Manager

kc

Attachments

cc: State of Utah - Division of Oil, Gas, & Mining
BLM - Vernal District Office
D. Weaver
J. Tigner - 2043
Vernal Office
File

EPA

ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT

NAME AND ADDRESS OF EXISTING PERMITTEE

ENRON OIL & GAS COMPANY
P.O. BOX 250
BIG PINEY WYOMING 83113

NAME AND ADDRESS OF SURFACE OWNER

LOCATE WELL AND OUTLINE UNIT ON SECTION PLAT — 640 ACRES

N E S

STATE: UTAH
COUNTY: UINTAH
PERMIT NUMBER: MT2623-03708

SURFACE LOCATION DESCRIPTION
NE ¼ OF NE ¼ OF NE ¼ SECTION 20 TOWNSHIP 9S RANGE 20E

LOCATE WELL IN TWO DIRECTIONS FROM NEAREST LINES OF QUARTER SECTION AND DRILLING UNIT

Surface Location 1037 ft. from (N/S) ____ line of quarter section
and 1033 ft. from (E XXX ____ line of quarter section

WELL ACTIVITY
XX Brine Disposal
☐ Enhanced Recovery
☐ Hydrocarbon Storage

TYPE OF PERMIT
☐ Individual
☐ Area
Number of Wells 1

Lease Name NATURAL BUTTES UNIT
Well Number 21-20B

MONTH	YEAR	INJECTION PRESSURE: AVERAGE PSIG	INJECTION PRESSURE: MAXIMUM PSIG	TOTAL VOLUME INJECTED: BBL	TOTAL VOLUME INJECTED: MCF	TUBING — CASING ANNULUS PRESSURE (OPTIONAL MONITORING): MINIMUM PSIG	MAXIMUM PSIG
WELL STARTED INJECTING 11-13-92							
NOV. 1992		464 psig	490 psig	2151 BBL	NA		
DEC. 1992		464 psig	490 psig	3736 BBL	NA		

CERTIFICATION

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32).

NAME AND OFFICIAL TITLE (Please type or print)

SIGNATURE

DATE SIGNED
JANUARY 25, 1993

EPA Form 7520-11 (2-84)

WATER ANALYSIS REPORT

Company	: ENRON OIL & GAS	Date	: 12-15-92
Address	:	Date Sampled	: 12-14-92
Lease	:	Analysis No.	: 1
Well	: 21-20B SWD		
Sample Pt.	: INJECTION PUMP DISCH		

	ANALYSIS			mg/L		* meq/L
1.	pH	7.5				
2.	H2S	0.0				
3.	Specific Gravity	1.210				
4.	Total Dissolved Solids			35188.9		
5.	Suspended Solids					
6.	Dissolved Oxygen					
7.	Dissolved CO2					
8.	Oil In Water					
9.	Phenolphthalein Alkalinity (CaCO3)					
10.	Methyl Orange Alkalinity (CaCO3)					
11.	Bicarbonate		HCO3	172.0	HCO3	2.8
12.	Chloride		Cl	19566.0	Cl	551.9
13.	Sulfate		SO4	1925.0	SO4	40.1
14.	Calcium		Ca	440.0	Ca	22.0
15.	Magnesium		Mg	109.6	Mg	9.0
16.	Sodium (calculated)		Na	12963.3	Na	563.9
17.	Iron		Fe	13.0		
18.	Barium		Ba	0.0		
19.	Strontium		Sr	0.0		
20.	Total Hardness (CaCO3)			1550.0		

PROBABLE MINERAL COMPOSITION

*milli equivalents per Liter

```
+-------+                      +-------+
|    22| *Ca <----- *HCO3      |      3|
|------|   /------->           |-------|
|     9| *Mg -----> *SO4       |     40|
|------|     <---------/       |-------|
|   564| *Na -----> *Cl        |    552|
+-------+                      +-------+
```

Saturation Values Dist. Water 20 C

CaCO3	13 mg/L
CaSO4 * 2H2O	2090 mg/L
BaSO4	2.4 mg/L

Compound	Equiv wt	X meq/L	= mg/L
Ca(HCO3)2	81.0	2.8	228
CaSO4	68.1	19.1	1302
CaCl2	55.5		
Mg(HCO3)2	73.2		
MgSO4	60.2	9.0	543
MgCl2	47.6		
NaHCO3	84.0		
Na2SO4	71.0	11.9	848
NaCl	58.4	551.9	32255

REMARKS:

Petrolite Oilfield Chemicals Group

Respectfully submitted,
MARC ROSE

SCALE TENDENCY REPORT

Company	: ENRON OIL & GAS	Date	: 12-15-92
Address	:	Date Sampled	: 12-14-92
Lease	:	Analysis No.	: 1
Well	: 21-20B SWD	Analyst	: MARC ROSE
Sample Pt.	: INJECTION PUMP DISCH		

STABILITY INDEX CALCULATIONS
(Stiff-Davis Method)
$CaCO_3$ Scaling Tendency

S.I. = 0.1 at 68 deg. F or 20 deg. C
S.I. = 0.1 at 77 deg. F or 25 deg. C
S.I. = 0.2 at 104 deg. F or 40 deg. C
S.I. = 0.4 at 140 deg. F or 60 deg. C
S.I. = 0.5 at 176 deg. F or 80 deg. C

****

CALCIUM SULFATE SCALING TENDENCY CALCULATIONS
(Skillman-McDonald-Stiff Method)
Calcium Sulfate

S = 4188 at 68 deg. F or 20 deg C
S = 4266 at 77 deg. F or 25 deg C
S = 4406 at 104 deg. F or 40 deg C
S = 4421 at 140 deg. F or 60 deg C
S = 4292 at 176 deg. F or 80 deg C

Petrolite Oilfield Chemicals Group

Respectfully submitted,
MARC ROSE

ENRON
Oil & Gas Company

P.O. Box 250 Big Piney, Wyoming 83113 (307) 276-3331

January 25, 1993

Mr. Chuck Williams
U.S. Environmental Protection Agency
Region VIII - 8WM-DW
999 18th Street, Suite 500
Denver, Colorado 80202-2466

RE: ANNUAL DISPOSAL/INJECTION WELL
MONITORING REPORT
NATURAL BUTTES UNIT 21-20B
NE/NE, SEC. 20, T9S, R20E
UINTAH, UTAH

Dear Mr. Williams:

Please find attached, the Annual Disposal/Injection Well Monitoring and water analysis reports for Natural Buttes Unit 21-20B SWD well.

If additional information is required, please contact Jim Schaefer of this office.

Sincerely,

C C Parsons

C.C. Parsons
District Manager

kc

Attachments

cc: State of Utah - Division of Oil, Gas, & Mining
BLM - Vernal District Office
D. Weaver
J. Tigner - 2043
Vernal Office
File

EPA ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT

NAME AND ADDRESS OF EXISTING PERMITTEE

ENRON OIL & GAS COMPANY
P.O. BOX 250
BIG PINEY WYOMING 83113

NAME AND ADDRESS OF SURFACE OWNER

LOCATE WELL AND OUTLINE UNIT ON SECTION PLAT — 640 ACRES

N E S

STATE: UTAH COUNTY: UINTAH PERMIT NUMBER: MT2623-03708

SURFACE LOCATION DESCRIPTION: NE ¼ OF NE ¼ OF NE ¼ SECTION 20 TOWNSHIP 9S RANGE 20E

LOCATE WELL IN TWO DIRECTIONS FROM NEAREST LINES OF QUARTER SECTION AND DRILLING UNIT

Surface Location 1037 ft. from (N/S) ____ Line of quarter section
and 1033 ft. from (E XX ____ Line of quarter section

WELL ACTIVITY: XX Brine Disposal; Enhanced Recovery; Hydrocarbon Storage

TYPE OF PERMIT: Individual; Area; Number of Wells 1

Lease Name NATURAL BUTTES UNIT Well Number 21-20B

MONTH	YEAR	INJECTION PRESSURE AVERAGE PSIG	INJECTION PRESSURE MAXIMUM PSIG	TOTAL VOLUME INJECTED BBL	TOTAL VOLUME INJECTED MCF	TUBING — CASING ANNULUS PRESSURE (OPTIONAL MONITORING) MINIMUM PSIG	MAXIMUM PSIG
WELL STARTED INJECTING 11-13-92							
NOV.	1992	464 psig	490 psig	2151 BBL	NA		
DEC.	1992	464 psig	490 psig	3736 BBL	NA		

CERTIFICATION

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32).

NAME AND OFFICIAL TITLE (Please type or print)

SIGNATURE

DATE SIGNED: JANUARY 25, 1993

EPA Form 7520-11 (2-84)

EPA Final Permit No. MT2623-03708

WATER ANALYSIS REPORT

Company	: ENRON OIL & GAS	Date	: 12-15-92
Address	:	Date Sampled	: 12-14-92
Lease	:	Analysis No.	: 1
Well	: 21-20B SWD		
Sample Pt.	: INJECTION PUMP DISCH		

	ANALYSIS			mg/L		* meq/L
1.	pH	7.5				
2.	H2S	0.0				
3.	Specific Gravity	1.210				
4.	Total Dissolved Solids			35188.9		
5.	Suspended Solids					
6.	Dissolved Oxygen					
7.	Dissolved CO2					
8.	Oil In Water					
9.	Phenolphthalein Alkalinity (CaCO3)					
10.	Methyl Orange Alkalinity (CaCO3)					
11.	Bicarbonate		HCO3	172.0	HCO3	2.8
12.	Chloride		Cl	19566.0	Cl	551.9
13.	Sulfate		SO4	1925.0	SO4	40.1
14.	Calcium		Ca	440.0	Ca	22.0
15.	Magnesium		Mg	109.6	Mg	9.0
16.	Sodium (calculated)		Na	12963.3	Na	563.9
17.	Iron		Fe	13.0		
18.	Barium		Ba	0.0		
19.	Strontium		Sr	0.0		
20.	Total Hardness (CaCO3)			1550.0		

PROBABLE MINERAL COMPOSITION

*milli equivalents per Liter

```
+-------+                         +-------+
|    22| *Ca <----- *HCO3         |      3|
|------|    /-------->            |------|
|     9| *Mg -----> *SO4          |     40|
|------|      <---------/         |------|
|   564| *Na -----> *Cl           |    552|
+-------+                         +-------+
```

Saturation Values Dist. Water 20 C

CaCO3	13 mg/L
CaSO4 * 2H2O	2090 mg/L
BaSO4	2.4 mg/L

Compound	Equiv wt	X meq/L	= mg/L
Ca(HCO3)2	81.0	2.8	228
CaSO4	68.1	19.1	1302
CaCl2	55.5		
Mg(HCO3)2	73.2		
MgSO4	60.2	9.0	543
MgCl2	47.6		
NaHCO3	84.0		
Na2SO4	71.0	11.9	848
NaCl	58.4	551.9	32255

REMARKS:

Petrolite Oilfield Chemicals Group

Respectfully submitted,
MARC ROSE

SCALE TENDENCY REPORT

Company	: ENRON OIL & GAS	Date	: 12-15-92
Address	:	Date Sampled	: 12-14-92
Lease	:	Analysis No.	: 1
Well	: 21-20B SWD	Analyst	: MARC ROSE
Sample Pt.	: INJECTION PUMP DISCH		

STABILITY INDEX CALCULATIONS
(Stiff-Davis Method)
$CaCO_3$ Scaling Tendency

S.I. = 0.1 at 68 deg. F or 20 deg. C
S.I. = 0.1 at 77 deg. F or 25 deg. C
S.I. = 0.2 at 104 deg. F or 40 deg. C
S.I. = 0.4 at 140 deg. F or 60 deg. C
S.I. = 0.5 at 176 deg. F or 80 deg. C

****

CALCIUM SULFATE SCALING TENDENCY CALCULATIONS
(Skillman-McDonald-Stiff Method)
Calcium Sulfate

S = 4188 at 68 deg. F or 20 deg C
S = 4266 at 77 deg. F or 25 deg C
S = 4406 at 104 deg. F or 40 deg C
S = 4421 at 140 deg. F or 60 deg C
S = 4292 at 176 deg. F or 80 deg C

Petrolite Oilfield Chemicals Group

Respectfully submitted,
MARC ROSE

Form Appr CMB No. 2040-0042. Expires 9-30-91

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, DC 20460

EPA ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT

FEB 10 1995
DIV OF OIL, GAS & MINING

NAME AND ADDRESS OF EXISTING PERMITTEE
ENRON OIL & GAS COMPANY
P.O. BOX 250, BIG PINEY, WYOMING 83113

NAME AND ADDRESS OF SURFACE OWNER
SAME

LOCATE WELL AND OUTLINE UNIT ON SECTION PLAT - 640 ACRES

N
W E
S

STATE: **UTAH**
COUNTY: **UINTAH**
PERMIT NUMBER: **MT 2623-03708**

SURFACE LOCATION DESCRIPTION
NE 1/4 OF NE 1/4 OF NE 1/4, SECTION 20 TOWNSHIP 9S RANGE 20E

LOCATE WELL IN TWO DIRECTIONS FROM NEAREST LINES OF QUARTER SECTION AND DRILLING UNIT

SURFACE LOCATION 1037 ft. from North Line of quarter section and 1033 ft. from East Line of quarter section.

WELL ACTIVITY
- [x] BRINE DISPOSAL
- [ ] ENHANCED RECOVERY
- [ ] HYDROCARBON STORAGE

TYPE OF PERMIT
- [ ] INDIVIDUAL
- [ ] AREA

NUMBER OF WELLS 1

LEASE NAME **NATURAL BUTTES** WELL NUMBER **21-20B**

MONTH YEAR	INJECTION PRESSURE AVG. PSIG	INJECTION PRESSURE MAX PSIG	TOTAL VOLUME INJECTED BBL	TOTAL VOLUME INJECTED MCF	TUBING - CASING ANNULUS PRESSURE (OPTIONAL MONITORING) MIN PSIG	TUBING - CASING ANNULUS PRESSURE (OPTIONAL MONITORING) MAX PSIG
Jan-95	408		3,862	0		
Feb-95	339		3,800	0		
Mar-95	394		5,700	0		
Apr-95	438		4,910	0		
May-95	508		6,650	0		
Jun-95	527		6352	0		
Jul-95	418		6,348	0		
Aug-95	334		6,410	0		
Sep-95	393		6,080	0		
Oct-95	451		3,770	0		
Nov-95	503		6,210	0		
Dec-95	338		6,260	0		

CERTIFICATION

I certify under the penalty of law that I have personally examined and an familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32).

NAME AND OFFICIAL TITLE (Please type or print)	SIGNATURE	DATE SIGNED
C.C. PARSONS DIVISION OPERATIONS MANAGER	CC Parsons	2-8-95

Champion Technologies, Inc.
2060 SOUTH 1500 EAST
VERNAL, UTAH 84078

Telephone (801) 789-4327

WATER ANALYSIS REPORT

Company: ENRON
Address:
Field/Lease: SWD 21-20B

Project #: 940758

Report For: GEORGE MCBRIDE
cc.
cc.
cc.

Date Sampled: 2-2-95

Date Received: 2-2-95

Date Reported: 2-6-95

Service Engineer: Ed Schwarz

Chemical Component	SWD
Chloride (mg/l)	11400
Sulfate (mg/l)	1219
Carbonate (mg/l)	0
Bicarbonate (mg/l)	384
Calcium (mg/l)	408
Magnesium (mg/l)	63
Iron (mg/l)	34
Barium (mg/l)	n/d
Strontium (mg/l)	n/d
Sodium (mg/l)	7533
pH	7.0
Ionic Strength	0.38
Specific Gravity	1.010
SI@20C (68F)	-0.34
SI@25C (77F)	-0.22
SI@30C (86F)	-0.11
SI@40C (104F)	0.15
SI@50C (122F)	0.30
SI@60C (140F)	0.68
SI@70C (158F)	0.88
SI@80C (176F)	1.24
SI@90C (194F)	1.55
TDS (mg/l)	21041
Temperature (F)	
Dissolved CO2 (ppm)	70
Dissolved H2S (ppm)	2
Dissolved O2 (ppm)	n/d

ctech\water1.wk1

ENRON
Oil & Gas Company
P.O. Box 250 Big Piney, WY 83113 (307) 276-3331

43-047-30359
(SWD)

RECEIVED
FEB 10 1995
DIV OF OIL, GAS & MINING

CERTIFIED

February 8, 1995

Mr. Thomas J. Pike, Chief
U.S. Environmental Protection Agency
Region VIII - 8WM-DW/UIC-I
999 18th Street, Suite 500
Denver, Colorado 80202-2466

RE: ANNUAL DISPOSAL/INJECTION WELLS MONITORING REPORT

Dear Mr. Pike:

Please find attached, the Annual Disposal/Injection Well Monitoring and water analysis reports for the Natural Buttes Unit 21-20B SWD well in the NE/NE of Section 20, T9S, R20E, Uintah County, Utah and the Annual Disposal/Injection Well Monitoring report for the Stagecoach Unit 11-22 SWD well in the NE/SE of Section 22, T8S, R21E, Uintah County, Utah, for 1994.

If additional information is required, please contact Jim Schaefer at this office.

Sincerely,

CC Parsons

C.C. Parsons
Division Operations Manager

kc

cc: State of Utah - Division of Oil, Gas & Mining
BLM - Vernal District Office
D. Weaver
J. Tigner - 2014
Vernal Office
File

UTAH DIVISION OF OIL, GAS AND MINING
EQUIPMENT INVENTORY

Operator: ENRON OIL & GAS CO. Lease: State:___ Federal: X Indian:___ Fee:___

Well Name: NBU 21-20B API Number: 43-047-30359

Section: 20 Township: 9S Range: 20E County: UINTAH Field: NATURAL BUTTES

Well Status: WIW Well Type: Oil:_____ Gas:_____

PRODUCTION LEASE EQUIPMENT: YES CENTRAL BATTERY:_____

Y Well head N Boiler(s) N Compressor N Separator(s)
N Dehydrator(s) Y Shed(s) Y Line Heater(s) N Heated Separator
N VRU N Heater Treater(s)

PUMPS:
X Triplex ____ Chemical ____ Centrifugal

LIFT METHOD:
____ Pumpjack ____ Hydraulic ____ Submersible ____ Flowing

GAS EQUIPMENT:

X Gas Meters X Purchase Meter ____ Sales Meter

TANKS: NUMBER		SIZE	
N	Oil Storage Tank(s)		BBLS
X	Water Tank(s)	2-400 BARREL W/BURNERS	BBLS
	Power Water Tank		BBLS
	Condensate Tank(s)		BBLS
	Propane Tank		

REMARKS: TRIPLEX PUMP W/SHED RUNNING AT 475 PSI. HALLIBURTON FLOW TOTALIZER SHOWING 5041013. LOCATION IS FENCED WITH GATES.

Location central battery: Qtr/Qtr:_____ Section: 20 Township: 9S Range: 20E

Inspector: DENNIS INGRAM Date: 4/29/93

STATE OF UTAH
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL, GAS AND MINING

FORM 9

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill new wells, significantly deepen existing wells below current bottom-hole depth, reenter plugged wells, or to drill horizontal laterals. Use APPLICATION FOR PERMIT TO DRILL form for such proposals.

5. LEASE DESIGNATION AND SERIAL NUMBER:

6. IF INDIAN, ALLOTTEE OR TRIBE NAME:

7. UNIT or CA AGREEMENT NAME:

1. TYPE OF WELL OIL WELL ☐ GAS WELL ☐ OTHER ____

8. WELL NAME and NUMBER: Exhibit "A"

2. NAME OF OPERATOR: El Paso Production Oil & Gas Company

9. API NUMBER:

3. ADDRESS OF OPERATOR: 368 South 1200 East CITY Vernal STATE Utah ZIP 84078 PHONE NUMBER: 435-789-4433

10. FIELD AND POOL, OR WILDCAT:

4. LOCATION OF WELL

FOOTAGES AT SURFACE:

COUNTY:

QTR/QTR, SECTION, TOWNSHIP, RANGE, MERIDIAN:

STATE: UTAH

11. CHECK APPROPRIATE BOXES TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION		
☐ NOTICE OF INTENT (Submit in Duplicate)	☐ ACIDIZE	☐ DEEPEN	☐ REPERFORATE CURRENT FORMATION
Approximate date work will start:	☐ ALTER CASING	☐ FRACTURE TREAT	☐ SIDETRACK TO REPAIR WELL
	☐ CASING REPAIR	☐ NEW CONSTRUCTION	☐ TEMPORARILY ABANDON
	☐ CHANGE TO PREVIOUS PLANS	☐ OPERATOR CHANGE	☐ TUBING REPAIR
	☐ CHANGE TUBING	☐ PLUG AND ABANDON	☐ VENT OR FLARE
☐ SUBSEQUENT REPORT (Submit Original Form Only)	☐ CHANGE WELL NAME	☐ PLUG BACK	☐ WATER DISPOSAL
Date of work completion:	☐ CHANGE WELL STATUS	☐ PRODUCTION (START/RESUME)	☐ WATER SHUT-OFF
	☐ COMMINGLE PRODUCING FORMATIONS	☐ RECLAMATION OF WELL SITE	☒ OTHER: Name Change
	☐ CONVERT WELL TYPE	☐ RECOMPLETE - DIFFERENT FORMATION	

12. DESCRIBE PROPOSED OR COMPLETED OPERATIONS. Clearly show all pertinent details including dates, depths, volumes, etc.

As a result of the merger between The Coastal Corporation and a wholly owned subsidary of El Paso Energy Corporation, the name of Coastal Oil & Gas Corporation has been changed to El Paso Production Oil & Gas Company effective March 9, 2001.

See Exhibit "A"

Bond # 400JU0708

Coastal Oil & Gas Corporation

NAME (PLEASE PRINT) John T. Elzner TITLE Vice President

SIGNATURE DATE 06-15-01

El Paso Production Oil & Gas Company

NAME (PLEASE PRINT) John T. Elzner TITLE Vice President

SIGNATURE DATE 06-15-01

(This space for State use only)

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JUN 19 2001

DIVISION OF OIL, GAS AND MINING

(5/2000)

(See Instructions on Reverse Side)

STATE OF UTAH
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL, GAS AND MINING

UIC FORM 5

TRANSFER OF AUTHORITY TO INJECT

Well Name and Number	API Number
EXHIBIT "A"	
Location of Well	Field or Unit Name
Footage : County :	Lease Designation and Number
QQ, Section, Township, Range: State : UTAH	

EFFECTIVE DATE OF TRANSFER: 03-09-01

CURRENT OPERATOR

Company: Coastal Oil & Gas Corporation
Address: 1368 South 1200 East
city Vernal state UT zip 84078
Phone: 435-789-4433

Name: John T. Elzner
Signature: [signature]
Title: Vice President
Date: 06-15-01

Comments: As a result of the merger between The Coastal Corporation and a wholly owned subsidary of El Paso Energy Corporation, the name of Coastal Oil & Gas Corporation has been changed to El Paso Production Oil & Gas Company effective March 9, 2001.
See EXHIBIT "A"

NEW OPERATOR

Company: El Paso Production Oil & Gas Company
Address: 1368 South 1200 East
city Vernal state UT zip 84078
Phone: 435-789-4433

Name: John T. Elzner
Signature: [signature]
Title: Vice President
Date: 06-15-01

Comments: NAME CHANGE

Bond Number 400JU0708

(This space for State use only)

Transfer approved by: [signature]
Title: Tech. Services Manager
Comments: Exhibit A as revised.

Approval Date: 6-21-01

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DIVISION OF
OIL, GAS AND MINING

(5/2000)

EXHIBIT "A"

NAME CHANGE FROM COASTAL OIL & GAS CORPORATION TO EL PASO PRODUCTION OIL & GAS COMPANY

API Well No.	Well Name	Well Status	Well Type	Location(T-R)	Section
43-013-30361-00-00	ALLRED 2-16A3	Active Well	Water Disposal	1S-3W	16
43-013-30370-00-00	UTE TRIBAL 1-25A3	Producing Well	Oil Well	1S-3W	25
43-013-30362-00-00	BIRCH 2-35A5	Active Well	Water Disposal	1S-5W	35
43-013-30337-00-00	G HANSON 2-4B3 SWD	Active Well	Water Disposal	2S-3W	4
43-013-30038-00-00	LAKE FORK 2-23B4	Active Well	Water Disposal	2S-4W	23
43-013-30371-00-00	LINDSAY RUSSELL 2-32B4	Active Well	Water Disposal	2S-4W	32
43-013-30121-00-00	TEW 1-9B5	Active Well	Water Disposal	2S-5W	9
43-013-30391-00-00	EHRICH 2-11B5	Active Well	Water Disposal	2S-5W	11
43-013-30340-00-00	LDS CHURCH 2-27B5	Active Well	Water Disposal	2S-5W	27
43-013-30289-00-00	RHOADES MOON 1-36B5	Shut_In	Oil Well	2S-5W	36
43-013-30056-00-00	UTE 1-14C6	Active Well	Water Disposal	3S-6W	14
43-047-33597-00-00	NBU SWD 2-16	Spudded (Drilling commenced: Not yet completed)	Water Disposal	10S-21E	16
43-047-32344-00-00	NBU 205	Shut_In	Gas Well	10S-22E	9
43-047-15880-00-00	SOUTHMAN CANYON U 3	Active Well	Water Disposal	10S-23E	15
43-047-31822-00-00	UTE 26-1		Water Disposal	4S-1E	26
43-047-32784-00-00	STIRRUP STATE 32-6	Active Well	Water Injection	6S-21E	32
43-047-30359-00-00	NBU 21-20B	Active Well	Water Disposal	9S-20E	20
43-047-33449-00-00	OURAY SWD 1	Approved permit (APD); not yet spudded	Water Disposal	9S-21E	1
43-047-31996-00-00	NBU 159	Active Well	Water Disposal	9S-21E	35

State of Delaware

Office of the Secretary of State

I, HARRIET SMITH WINDSOR, SECRETARY OF STATE OF THE STATE OF DELAWARE, DO HEREBY CERTIFY THE ATTACHED IS A TRUE AND CORRECT COPY OF THE CERTIFICATE OF AMENDMENT OF "COASTAL OIL & GAS CORPORATION", CHANGING ITS NAME FROM "COASTAL OIL & GAS CORPORATION" TO "EL PASO PRODUCTION OIL & GAS COMPANY", FILED IN THIS OFFICE ON THE NINTH DAY OF MARCH, A.D. 2001, AT 11 O'CLOCK A.M.

RECEIVED

JUN 19 2001

DIVISION OF
OIL, GAS AND MINING

Harriet Smith Windsor

Harriet Smith Windsor, Secretary of State

0610204 8100

AUTHENTICATION: 1061007

010162788

DATE: 04-03-01

CERTIFICATE OF AMENDMENT

OF

CERTIFICATE OF INCORPORATION

COASTAL OIL & GAS CORPORATION (the "Company"), a corporation organized and existing under and by virtue of the General Corporation Law of the State of Delaware, DOES HEREBY CERTIFY:

FIRST: That the Board of Directors of the Company, by the unanimous written consent of its members, filed with the minutes of the Board, adopted a resolution proposing and declaring advisable the following amendment to the Certificate of Incorporation of the Company:

> RESOLVED that it is deemed advisable that the Certificate of Incorporation of this Company be amended, and that said Certificate of Incorporation be so amended, by changing the Article thereof numbered "FIRST." so that, as amended, said Article shall be and read as follows:
>
> "FIRST. The name of the corporation is El Paso Production Oil & Gas Company."

SECOND: That in lieu of a meeting and vote of stockholders, the stockholders entitled to vote have given unanimous written consent to said amendment in accordance with the provisions of Section 228 of the General Corporation Law of the State of Delaware.

THIRD: That the aforesaid amendment was duly adopted in accordance with the applicable provisions of Sections 242 and 228 of the General Corporation Law of the State of Delaware.

IN WITNESS WHEREOF, said COASTAL OIL & GAS CORPORATION has caused this certificate to be signed on its behalf by a Vice President and attested by an Assistant Secretary, this 9th day of March 2001.

COASTAL OIL & GAS CORPORATION

David L. Siddall
David L. Siddall
Vice President

Attest:

Margaret E. Roark
Margaret E. Roark, Assistant Secretary

STATE OF DELAWARE
SECRETARY OF STATE
DIVISION OF CORPORATIONS
FILED 11:00 AM 03/09/2001
010118394 – 0610204

RECEIVED
JUN 19 2001
DIVISION OF
OIL, GAS AND MINING

I, HARRIET SMITH WINDSOR, SECRETARY OF STATE OF THE STATE OF DELAWARE, DO HEREBY CERTIFY THAT THE SAID "COASTAL OIL & GAS CORPORATION", FILED A CERTIFICATE OF AMENDMENT, CHANGING ITS NAME TO "EL PASO PRODUCTION OIL & GAS COMPANY", THE NINTH DAY OF MARCH, A.D. 2001, AT 11 O'CLOCK A.M.

RECEIVED
JUN 19 2001
DIVISION OF
OIL, GAS AND MINING

Harriet Smith Windsor
Harriet Smith Windsor, Secretary of State

0610204 8320
010202983

AUTHENTICATION: 1103213
DATE: 04-27-01

EL PASO PRODUCTION OIL & GAS COMPANY

CERTIFICATE OF INCUMBENCY

I, Margaret E. Roark, do hereby certify that I am a duly elected, qualified and acting Assistant Secretary of EL PASO PRODUCTION OIL & GAS COMPANY, a Delaware corporation (the "Company"), and that, as such, have the custody of the corporate records and seal of said Company; and

I do hereby further certify that the persons listed on the attached Exhibit A have been elected, qualified and are now acting in the capacities indicated, as of the date of this Certificate.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed the corporate seal of El Paso Production Oil & Gas Company this 18th day of April 2001.

Margaret E. Roark

Margaret E. Roark, Assistant Secretary

RECEIVED

JUN 19 2001

DIVISION OF
OIL, GAS AND MINING

Division of Oil, Gas and Mining

OPERATOR CHANGE WORKSHEET

ROUTING		
1. GLH		4-KAS ✓
2. CDW		5-LP ✓ 6/25
3. JLT		6-FILE

Enter date after each listed item is completed

Change of Operator (Well Sold) | Designation of Agent

Operator Name Change (Only) | X **Merger**

The operator of the well(s) listed below has changed, effective: **3-09-2001**

FROM: (Old Operator):	**TO:** (New Operator):
COASTAL OIL & GAS CORPORATION	EL PASO PRODUCTION OIL & GAS COMPANY
Address: 9 GREENWAY PLAZA STE 2721	Address: 9 GREENWAY PLAZA STE 2721 RM 2975B
HOUSTON, TX 77046-0995	HOUSTON, TX 77046-0995
Phone: 1-(713)-418-4635	Phone: 1-(832)-676-4721
Account N0230	Account N1845

CA No. **Unit:**

WELL(S)

NAME		API NO	ENTITY NO	SEC TWN RNG	LEASE TYPE	WELL TYPE	WELL STATUS
ALLRED 2-16A3		43-013-30361	99996	16-01S-03W	FEE	WD	A
BIRCH 2-35A5		43-013-30362	99996	35-01S-05W	FEE	WD	A
G HANSON 2-4B3 SWD		43-013-30337	99990	04-02S-03W	FEE	WD	A
LAKE FORK 2-23B4		43-013-30038	1970	23-02S-04W	FEE	WD	A
LINDSAY RUSSELL 2-32B4		43-013-30371	99996	32-02S-04W	FEE	WD	A
TEW 1-9B5		43-013-30121	1675	09-02S-05W	FEE	WD	A
EHRICH 2-11B5		43-013-30391	99990	11-02S-05W	FEE	WD	A
LDS CHURCH 2-27B5		43-013-30340	99990	27-02S-05W	FEE	WD	A
UTE 1-14C6		43-013-30056	12354	14-03S-06W	INDIAN	WD	A
SOUTHMAN CANYON U 3		43-047-15880	99990	15-10S-23E	FEDERAL	WD	A
STIRRUP STATE 32-6	(HORSESHOE BEND UNIT)	43-047-32784	12323	32-06S-21E	STATE	WIW	A
NBU 21-20B	(NATURAL BUTTES UNIT)	43-047-30359	2900	20-09S-20E	FEDERAL	WD	A
NBU 159	(NATURAL BUTTES UNIT)	43-047-31996	2900	35-09S-21E	FEDERAL	WD	A

OPERATOR CHANGES DOCUMENTATION

1. (R649-8-10) Sundry or legal documentation was received from the **FORMER** operator on: 06/19/2001

2. (R649-8-10) Sundry or legal documentation was received from the **NEW** operator on: 06/19/2001

3. The new company has been checked through the **Department of Commerce, Division of Corporations Database on:** 06/21/2001

4. Is the new operator registered in the State of Utah: YES Business Number: 608186-0143

5. If **NO**, the operator was contacted contacted on: N/A

6. **Federal and Indian Lease Wells:** The BLM and or the BIA has approved the (merger, name change, or operator change for all wells listed on Federal or Indian leases on: N/A

7. **Federal and Indian Units:** The BLM or BIA has approved the successor of unit operator for wells listed on: N/A

8. **Federal and Indian Communization Agreements ("CA"):** The BLM or the BIA has approved the operator change for all wells listed involved in a CA on: N/A

9. **Underground Injection Control ("UIC")** The Division has approved UIC Form 5, **Transfer of Authority to Inject,** for the enhanced/secondary recovery unit/project for the water disposal well(s) listed on: N/A

DATA ENTRY:

1. Changes entered in the **Oil and Gas Database on:** 06/21/2001

2. Changes have been entered on the **Monthly Operator Change Spread Sheet on:** 06/21/2001

3. Bond information entered in RBDMS on: 06/20/2001

4. Fee wells attached to bond in RBDMS on: 06/21/2001

STATE BOND VERIFICATION:

1. State well(s) covered by Bond No.: 400JU0705

FEE WELLS - BOND VERIFICATION/LEASE INTEREST OWNER NOTIFICATION:

1. (R649-3-1) The **NEW** operator of any fee well(s) listed has furnished a bond: 400JU0708

2. The **FORMER** operator has requested a release of liability from their bond on: COMPLETION OF OPERATOR CHANGE
   The Division sent response by letter on: N/A

3. (R649-2-10) The **FORMER** operator of the Fee wells has been contacted and informed by a letter from the Division of their responsibility to notify all interest owners of this change on: COMPLETION OF OPERATOR CHANGE

FILMING:

1. All attachments to this form have been **MICROFILMED** on: 7-26-01

FILING:

1. **ORIGINALS/COPIES** of all attachments pertaining to each individual well have been filled in each well file on: ____________

COMMENTS: Master list of all wells involved in operator change from Coastal Oil & Gas Corporation to El Paso Production Oil and Gas Company shall be retained in the "Operator Change File".

WESTPORT OIL AND GAS COMPANY, L.P.

410 Seventeenth Street #2300 Denver Colorado 80202-4436
Telephone: 303 573 5404 Fax: 303 573 5609

February 1, 2002

Department of the Interior
Bureau of Land Management
2850 Youngfield Street
Lakewood, CO 80215-7093
Attention: Ms. Martha Maxwell

RE: BLM Bond CO-1203
BLM Nationwide Bond 158626364
Surety – Continental Casualty Company
Belco Energy Corporation merger into Westport Oil and Gas Company, Inc.
Conversion of Westport Oil and Gas Company, Inc., into Westport Oil and Gas Company, L.P.
Assumption Rider – Westport Oil and Gas Company, L.P.

Dear Ms. Maxwell:

Pursuant to our recent conversations, please find the following list of enclosures for the BLM's consideration and approval:

Two (2) Assumption Riders, fully executed originals.
Copies of Belco Energy Corporation merger into Westport Oil and Gas Company, Inc.
Copies of Westport Oil and Gas Company, Inc., conversion into Westport Oil and Gas Company, L.P.
List of all Federal/BIA/State Leases - Belco/Westport's leases – in all states.

Please inform us of any additional information needed to complete the change to Westport Oil and Gas Company, L.P., as operator of record.

I thank you for your assistance and cooperation in this matter. Please do not hesitate contacting the undersigned, should a question arise.

Sincerely,
Westport Oil and Gas Company, L.P.

Debby J. Black

Debby J. Black
Engineer Technician

Encl;

United States Department of the Interior

BUREAU OF LAND MANAGEMENT
Utah State Office
P.O. Box 45155
Salt Lake City, UT 84145-0155

RECEIVED

FEB 22 2002

DIVISION OF
OIL, GAS AND MINING

In Reply Refer To:
3106
UTU-25566 et al
(UT-924)

FEB 21 2002

NOTICE

Westport Oil and Gas Company L.P. : Oil and Gas
410 Seventeenth Street, #2300 :
Denver Colorado 80215-7093 :

Name Change Recognized

Acceptable evidence has been received in this office concerning the name change of Westport Oil and Gas Company, Inc. into Westport Oil and Gas Company, L.P. with Westport Oil and Gas Company, L.P. being the surviving entity.

For our purposes, the name change is recognized effective December 31, 2001.

The oil and gas lease files identified have been noted as to the name change. The exhibit was compiled from a list of leases obtained from our computer program. We have not abstracted the lease files to determine if the entities affected by this name change hold an interest in the leases identified nor have we attempted to identify leases where the entities are the operator on the ground maintaining no vested recorded title or operating rights interests. We will be notifying the Minerals Management Service and all applicable Bureau of Land Management offices of the change by a copy of this notice. If additional documentation for changes of operator are required by our Field Offices, you will be contacted by them.

If you identify additional leases in which the entities maintain an interest, please contact this office and we will appropriately document those files with a copy of this Notice.

Due to the name change, the name of the principal/obligor on the bond is required to be changed from Westport Oil and Gas Company, Inc. to Westport Oil and Gas Company, L.P.. You may accomplish this either by consent of surety rider on the original bond or a rider to the original bond. The bonds are held in Colorado.

UTU-03405
UTU-20895
UTU-25566
UTU-43156
UTU-49518
UTU-49519
UTU-49522
UTU-49523

Robert Lopez
Chief, Branch of
Minerals Adjudication

cc: Moab Field Office
Vernal Field Office
MMS, Reference Data Branch, MS3130, PO Box 5860, Denver CO 80217
State of Utah, DOGM, Attn: Jim Thompson (Ste. 1210), Box 145801, SLC UT 84114
Teresa Thompson (UT-922)
Joe Incardine (UT-921)

UNITED STATES GOVERNMENT

memorandum

Branch of Real Estate Services
Uintah & Ouray Agency

Date: 5 December, 2002

Reply to Attn of: Supervisory Petroleum Engineer

Subject: Modification of Utah Division of Oil, Gas and Mining Regulations

To: Director, Utah Division of Oil, Gas and Mining Division: John Baza

We have been advised of changes occurring with the operation of your database for Change of Operator. You will be modifying your records to reflect Change of Operator once you have received all necessary documentation from the companies involved, and perhaps in advance of our Notice of Concurrence/Approval of Change of Operator where Indian leases are involved.

We have no objection.

With further comment to Rulemaking, I wish to comment concerning the provision of Exhibits for upcoming Hearings. I would like to see the Uintah & Ouray Agency, BIA, and the Ute Indian Tribe, Energy & Mineral Resources Department added to the list of those parties that receive advance Exhibits so as to allow us to have research time prior to Hearing dates. We will be able to provide a more informed recommendation to the Oil, Gas and Mining Board. It would be best if we would receive only those Exhibits that concern Indian lands, specifically on or adjacent to Indian lands. This may be a difficult situation to attain, as it is not always clear where 'on or adjacent' occurs.

I am aware that you have gone to extra effort to correct this matter already, and I fully appreciate it. My request is intended only to allow the addition of Uintah & Ouray Agency and Ute Indian Tribe to the official listing.

We appreciate you concern, and hope that these comments are timely enough for consideration in the revision process.

Charles H Cameron

CC: Minerals & Mining Section of RES
Ute Energy & Mineral Resources Department: Executive Director
chrono

United States Department of the Interior

BUREAU OF INDIAN AFFAIRS
Washington, D.C. 20240

IN REPLY REFER TO:
Real Estate Services

FEB 10 2003

Carroll A. Wilson
Principal Landman
Westport Oil and Gas Company, L.P.
1368 South 1200 East
Vernal, Utah 84078

Dear Mr. Wilson:

This is in response to your request for approval of RLI Insurance Company's Nationwide Oil and Gas Lease Bond No. RLB0005239 executed effective December 17, 2002, ($150,000 coverage) with Westport Oil and Gas Company, L. P., as principal.

This bond is hereby approved as of the date of this correspondence and will be retained in the Bureau of Indian Affairs' Division of Real Estate Services, 1849 C Street, NW, MS-4512-MIB, Washington, D.C. 20240. All Bureau oil and gas regional offices and the surety are being informed of this action.

In cases where you have existing individual and/or collective bonds on file with one or more of our regional offices, you may now request those offices, directly, to terminate in lieu of coverage under this Nationwide Bond.

Enclosed is a copy of the approved bond for your files. If we may be of further assistance in this matter, please advise.

Sincerely,

Terry E. Bowman

ACTING Director, Office of Trust Responsibilities

Enclosure

STATE OF UTAH
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL, GAS AND MINING

FORM 9

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill new wells, significantly deepen existing wells below current bottom-hole depth, reenter plugged wells, or to drill horizontal laterals. Use APPLICATION FOR PERMIT TO DRILL form for such proposals.

5. LEASE DESIGNATION AND SERIAL NUMBER:
6. IF INDIAN, ALLOTTEE OR TRIBE NAME:
7. UNIT or CA AGREEMENT NAME:
8. WELL NAME and NUMBER: Exhibit "A"
9. API NUMBER:
10. FIELD AND POOL, OR WILDCAT:

1. TYPE OF WELL OIL WELL ☐ GAS WELL ☐ OTHER ______

2. NAME OF OPERATOR: El Paso Production Oil & Gas Company

3. ADDRESS OF OPERATOR: 9 Greenway Plaza CITY Houston STATE TX ZIP 77064-0995 PHONE NUMBER: (832) 676-5933

4. LOCATION OF WELL

FOOTAGES AT SURFACE:

COUNTY:

QTR/QTR, SECTION, TOWNSHIP, RANGE, MERIDIAN:

STATE: UTAH

11. CHECK APPROPRIATE BOXES TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION		
☐ NOTICE OF INTENT (Submit in Duplicate)	☐ ACIDIZE	☐ DEEPEN	☐ REPERFORATE CURRENT FORMATION
Approximate date work will start:	☐ ALTER CASING	☐ FRACTURE TREAT	☐ SIDETRACK TO REPAIR WELL
	☐ CASING REPAIR	☐ NEW CONSTRUCTION	☐ TEMPORARILY ABANDON
	☐ CHANGE TO PREVIOUS PLANS	☑ OPERATOR CHANGE	☐ TUBING REPAIR
	☐ CHANGE TUBING	☐ PLUG AND ABANDON	☐ VENT OR FLARE
☐ SUBSEQUENT REPORT (Submit Original Form Only)	☐ CHANGE WELL NAME	☐ PLUG BACK	☐ WATER DISPOSAL
Date of work completion:	☐ CHANGE WELL STATUS	☐ PRODUCTION (START/RESUME)	☐ WATER SHUT-OFF
	☐ COMMINGLE PRODUCING FORMATIONS	☐ RECLAMATION OF WELL SITE	☐ OTHER:
	☐ CONVERT WELL TYPE	☐ RECOMPLETE - DIFFERENT FORMATION	

12. DESCRIBE PROPOSED OR COMPLETED OPERATIONS. Clearly show all pertinent details including dates, depths, volumes, etc.

Operator change to Westport Oil and Gas Company, L.P., 1670 Broadway, Suite 2800, Denver, CO. 80202-4800, effective December 17, 2002.

BOND # ______

State Surety Bond No. RLB0005236
Fee Bond No. RLB0005238

RECEIVED
FEB 2 8 2003
DIV. OF OIL, GAS & MINING

EL PASO PRODUCTION OIL & GAS COMPANY

By: [signature]
Jon R. Nelsen, Attorney-in-Fact

WESTPORT OIL AND GAS COMPANY, L.P.

NAME (PLEASE PRINT) David R. Dix TITLE Agent and Attorney-in-Fact

SIGNATURE [signature] DATE 12/17/02

(This space for State use only)

(5/2000) (See Instructions on Reverse Side)

Form 3160-5
(August 1999)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
OMB No. 1004-0135
Expires November 30, 2000

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or reenter an abandoned well. Use Form 3160-3 (APD) for such proposals.

SUBMIT IN TRIPLICATE – Other instructions on reverse side

5. Lease Serial No.
SEE ATTACHED EXHIBIT "A"

6. If Indian, Allottee or Tribe Name

7. If Unit or CA/Agreement, Name and/or No.

1. Type of Well
☐ Oil Well ☒ Gas Well ☐ Other

2. Name of Operator
WESTPORT OIL & GAS COMPANY, L.P.

8. Well Name and No.
SEE ATTACHED EXHIBIT "A"

3a. Address
P.O. BOX 1148 VERNAL, UT 84078

3b. Phone No. *(include area code)*
(435) 781-7023

9. API Well No.
SEE ATTACHED EXHIBIT "A"

10. Field and Pool, or Exploratory Area

4. Location of Well *(Footage, Sec., T., R., M., or Survey Description)*
SEE ATTACHED EXHIBIT "A"

11. County or Parish, State
UINTAH COUNTY, UT

12. CHECK APPROPRIATE BOX(ES) TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION			
☐ Notice of Intent	☐ Acidize	☐ Deepen	☐ Production (Start/Resume)	☐ Water Shut-Off
☐ Subsequent Report	☐ Alter Casing	☐ Fracture Treat	☐ Reclamation	☐ Well Integrity
☐ Final Abandonment Notice	☐ Casing Repair	☐ New Construction	☐ Recomplete	☒ Other SUCCESSOR OF OPERATOR
	☐ Change Plans	☐ Plug and Abandon	☐ Temporarily Abandon	
	☐ Convert to Injection	☐ Plug Back	☐ Water Disposal	

13. Describe Proposed or Completed Operations (clearly state all pertinent details, including estimated starting date of any proposed work and approximate duration the[reof]. If the proposal is to deepen directionally or recomplete horizontally, give subsurface locations and measured and true vertical depths of all pertinent markers and zo[nes]. Attach the Bond under which the work will be performed or provide the Bond No. on file with BLM/BIA. Required subsequent reports shall be filed within 30 [days] following completion of the involved operations. If the operation results in a multiple completion or recompletion in a new interval, a Form 3160-4 shall be filed [once] testing has been completed. Final Abandonment Notices shall be filed only after all requirements, including reclamation, have been completed, and the operator [has] determined that the site is ready for final inspection.

WESTPORT OIL & GAS COMPANY, L.P., IS CONSIDERED TO BE THE OPERATOR ON THE ATTACHED DESCRIBED LANDS AND IS RESPONSIBLE UNDER THE TERMS AND CONDITIONS OF THE LEASE FOR THE OPERATIONS CONDUCTED ON THE LEASED LANDS OR PORTIONS THEREOF, BOND COVERAGE FOR THIS WELL IS PROVIDED BY FEDERAL NATIONWIDE BOND NO. 158626364, EFFECTIVE FEBRUARY 1, 2002, AND BIA NATIONWIDE BOND NO. RLB0005239, EFFECTIVE FEBRUARY 10, 2003.

RECEIVED
MAR 0 4 2003
DIV. OF OIL, GAS & MINING

14. I hereby certify that the foregoing is true and correct
Name *(Printed/Typed)*
CHERYL CAMERON

Title
OPERATIONS

Signature
Cheryl Cameron

Date
March 4, 2003

THIS SPACE FOR FEDERAL OR STATE USE

Approved by

Title

Date

Conditions of approval, if any, are attached. Approval of this notice does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.

Office

Title 18 U.S.C. Section 1001, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

(Instructions on reverse)

DIVISION OF OIL, GAS AND MINING

TRANSFER OF AUTHORITY TO INJECT

Well Name and Number EXHIBIT "A"	API Number
Location of Well Footage :　　County : QQ, Section, Township, Range:　　State : UTAH	Field or Unit Name Lease Designation and Number

EFFECTIVE DATE OF TRANSFER: 12-17-0 2

CURRENT OPERATOR

Company: EL PASO PRODUCTION OIL & GAS COMPANY
Address: 1368 SOUTH 1200 EAST
city VERNAL state UT zip 84078
Phone: 435-789-4433
Comments:

Name: JON R. NELSEN
Signature: [signature]
Title: ATTORNEY-IN-FACT
Date: 12-17-02

NEW OPERATOR

Company: WESTPORT OIL AND GAS COMPANY L.P.
Address: 1670 BROADWAY, SUITE 2800
city DENVER state CO zip 80202-4800
Phone: 303-575-0177
Comments:

Name: DAVID R. DIX
Signature: [signature]
Title: AGENT, ATTORNEY-IN-FACT
Date: 12-17-02

(This space for State use only)

Transfer approved by: [signature]　　Approval Date: 3-6-03

Title: Tech. Services Manager

Comments: DOES not apply to NBU SWD 2-16 a P+A well.

(5/2000)

EXHIBIT "A"

TRANSFER OF AUTHORITY TO INJECT

STATE OF UTAH

DEPART OF NATURAL RESOURCES
DIVISION OF OIL, GAS AND MINING

WELL NAME	API	FOOTAGE	COUNTY	QUARTER QUARTER LOCATION	SECTION	TOWNSHIP	RANGE	STATE	FIELD OF UNIT NAME
SOUTHMAN CANYON U 3	4304715880	2180 FSL 400 FEL	UINTAH	NE/4NE/4SE/4	15	10S	23E	UTAH	SOUTHMAN CANYON
NBU 2[illegible]1-20B	4304730359	1037 FNL 1033 FEL	UINTAH	SW/WNE/4NE/4	20	09S	20E	UTAH	NATURAL BUTTES
NBU 159	4304731996	1958 FSL 1945 FWL	UINTAH	SW/4NE/4SW/4	35	09S	21E	UTAH	NATURAL BUTTES
STRRUP ST 32-6	4304732784	850 FNL 800 FEL	UINTAH	NE/4NE/4	32	06S	21E	UTAH	HORSESHOE BEND
OURAY SWD 1	4304733449	561 FNL 899 FEL	UINTAH	NE/4NE/4	01	09S	21'E	UTAH	NATURAL BUTTES
NBU SWD 2-16	4304733597	2486 FSL 1122 FEL	UINTAH	NW/4NE/4SE/4	16	10S	21E	UTAH	NATURAL BUTTES

Division of Oil, Gas and Mining

OPERATOR CHANGE WORKSHEET

ROUTING
1. GLH
2. CDW
3. FILE

X **Change of Operator (Well Sold)** Designation of Agent/Operator

Operator Name Change Merger

The operator of the well(s) listed below has changed, effective: **12-17-02**

FROM: (Old Operator):	**TO:** (New Operator):
EL PASO PRODUCTION OIL & GAS COMPANY	WESTPORT OIL & GAS COMPANY LP
Address: 9 GREENWAY PLAZA	Address: P O BOX 1148
HOUSTON, TX 77064-0995	VERNAL, UT 84078
Phone: 1-(832)-676-5933	Phone: 1-(435)-781-7023
Account No. N1845	Account No. N2115

CA No. **Unit:**

WELL(S)

NAME	SEC TWN RNG	API NO	ENTITY NO	LEASE TYPE	WELL TYPE	WELL STATUS
NBU 159	35-09S-21E	43-047-31996	2900	FEDERAL	SWD	A
STIRRUP STATE 32-6	32-06S-21E	43-047-32784	12323	STATE	SWD	A
NBU 21-20B	20-09S-20E	43-047-30359	2900	FEDERAL	SWD	A
OURAY SWD 1	01-09S-21E	43-047-33449	13274	FEE	SWD	I
NBU SWD 2-16 N/A	16-10S-21E	43-047-33597	13196	STATE	SWD	PA
SOUTHMAN CANYON 3	15-10S-23E	43-047-15880	99990	FEDERAL	SWD	A

OPERATOR CHANGES DOCUMENTATION

Enter date after each listed item is completed

1. (R649-8-10) Sundry or legal documentation was received from the **FORMER** operator on: 02/28/2003
2. (R649-8-10) Sundry or legal documentation was received from the **NEW** operator on: 03/04/2003
3. The new company has been checked through the **Department of Commerce, Division of Corporations Database on:** 03/06/2003
4. Is the new operator registered in the State of Utah: YES Business Number: 1355743-0181
5. If NO, the operator was contacted contacted on: ____

6. (R649-9-2)Waste Management Plan has been received on: IN PLACE

7. **Federal and Indian Lease Wells:** The BLM and or the BIA has approved the merger, name change, or operator change for all wells listed on Federal or Indian leases on: 12/31/2003

8. **Federal and Indian Units:**
The BLM or BIA has approved the successor of unit operator for wells listed on: N/A

9. **Federal and Indian Communization Agreements ("CA"):**
The BLM or BIA has approved the operator for all wells listed within a CA on: N/A

10. **Underground Injection Control ("UIC")** The Division has approved UIC Form 5, **Transfer of Authority to Inject,** for the enhanced/secondary recovery unit/project for the water disposal well(s) listed on: 03/06/2003

DATA ENTRY:

1. Changes entered in the **Oil and Gas Database on:** 03/07/2003
2. Changes have been entered on the **Monthly Operator Change Spread Sheet on:** 03/07/2003
3. Bond information entered in RBDMS on: N/A
4. Fee wells attached to bond in RBDMS on: N/A

STATE WELL(S) BOND VERIFICATION:

1. State well(s) covered by Bond Number: RLB 0005236

FEDERAL WELL(S) BOND VERIFICATION:

1. Federal well(s) covered by Bond Number: 158626364

INDIAN WELL(S) BOND VERIFICATION:

1. Indian well(s) covered by Bond Number: RLB 0005239

FEE WELL(S) BOND VERIFICATION:

1. (R649-3-1) The **NEW** operator of any fee well(s) listed covered by Bond Number RLB 0005238

2. The **FORMER** operator has requested a release of liability from their bond on: N/A
The Division sent response by letter on: N/A

LEASE INTEREST OWNER NOTIFICATION:

3. (R649-2-10) The **FORMER** operator of the fee wells has been contacted and informed by a letter from the Division of their responsibility to notify all interest owners of this change on: N/A

COMMENTS: COMPLETE LIST OF WELLS INVOLVING OPERATOR CHANGE MAY BE FOUND IN THE OPERATOR CHANGE FILE.

Division of Oil, Gas and Mining

OPERATOR CHANGE WORKSHEET

ROUTING
1. DJJ
2. CDW

X Change of Operator (Well Sold) Operator Name Change/Merger

The operator of the well(s) listed below has changed, effective: **1/6/2006**

FROM: (Old Operator):	**TO:** (New Operator):
N2115-Westport Oil & Gas Co., LP	N2995-Kerr-McGee Oil & Gas Onshore, LP
1368 South 1200 East	1368 South 1200 East
Vernal, UT 84078	Vernal, UT 84078
Phone: 1-(435) 781-7024	Phone: 1-(435) 781-7024

CA No. **Unit:**

WELL NAME	SEC TWN RNG	API NO	ENTITY NO	LEASE TYPE	WELL TYPE	WELL STATUS

OPERATOR CHANGES DOCUMENTATION

Enter date after each listed item is completed

1. (R649-8-10) Sundry or legal documentation was received from the **FORMER** operator on: 5/10/2006
2. (R649-8-10) Sundry or legal documentation was received from the **NEW** operator on: 5/10/2006
3. The new company was checked on the **Department of Commerce, Division of Corporations Database on:** 3/7/2006
4. Is the new operator registered in the State of Utah: YES Business Number: 1355743-0181

5a. (R649-9-2)Waste Management Plan has been received on: IN PLACE

5b. Inspections of LA PA state/fee well sites complete on: n/a 3 LA wells & all PA wells transferred

5c. Reports current for Production/Disposition & Sundries on: ok

6. **Federal and Indian Lease Wells:** The BLM and or the BIA has approved the merger, name change, or operator change for all wells listed on Federal or Indian leases on: BLM 3/27/2006 BIA not yet
7. **Federal and Indian Units:** The BLM or BIA has approved the successor of unit operator for wells listed on: 3/27/2006
8. **Federal and Indian Communization Agreements ("CA"):** The BLM or BIA has approved the operator for all wells listed within a CA on: n/a
9. **Underground Injection Control ("UIC")** The Division has approved UIC Form 5, **Transfer of Authority to Inject,** for the enhanced/secondary recovery unit/project for the water disposal well(s) listed on: 12/15/2006

DATA ENTRY:

1. Changes entered in the **Oil and Gas Database on:** 12/15/2006
2. Changes have been entered on the **Monthly Operator Change Spread Sheet on:** 12/15/2006
3. Bond information entered in RBDMS on: 12/15/2006
4. Fee/State wells attached to bond in RBDMS on: 12/16/2006
5. Injection Projects to new operator in RBDMS on:
6. Receipt of Acceptance of Drilling Procedures for APD/New on: n/a Name Change Only

BOND VERIFICATION:

1. Federal well(s) covered by Bond Number: CO1203
2. Indian well(s) covered by Bond Number: RLB0005239
3. (R649-3-1) The **NEW** operator of any fee well(s) listed covered by Bond Number RLB0005236

a. The **FORMER** operator has requested a release of liability from their bond on: n/a rider added KMG
The Division sent response by letter on:

LEASE INTEREST OWNER NOTIFICATION:

4. (R649-2-10) The **FORMER** operator of the fee wells has been contacted and informed by a letter from the Division of their responsibility to notify all interest owners of this change on: 5/16/2006

COMMENTS:

Westport Oil Gas Co LP (N2115) to Kerr-Mcgee Oil Gas Onshore, LP (N2995) sorted by Unit, Lease Type API

well_name	sec	twsp	rng	api	entity	lease	well	stat
WELLINGTON FED 44-6 SWD	06	140S	110E	4300730912	13919	Federal	WD	A
WELLINGTON FED 22-04 SWD	04	140S	110E	4300730967	14826	Federal	WD	A
SOUTHMAN CANYON U 3	15	100S	230E	4304715880	99990	Federal	WD	A
OURAY SWD 1	01	090S	210E	4304733449	13274	Fee	WD	A
				NATURAL BUTTES UNIT				
NBU 21-20B	20	090S	200E	4304730359	2900	Federal	WD	A
CIGE 9	36	090S	220E	4304730419	2900	State	WD	A
NBU 159	35	090S	210E	4304731996	2900	State	WD	A
NBU 47N2	30	100S	220E	4304730534	2900	Federal	WI	A
NBU 347	11	100S	220E	4304733709	2900	State	WI	A

STATE OF UTAH
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL, GAS AND MINING

UIC FORM 5

TRANSFER OF AUTHORITY TO INJECT

Well Name and Number: Several-See Attached	API Number:
Location of Well — Footage: ; County: Uintah	Field or Unit Name: Natural Buttes
QQ, Section, Township, Range: ; State: UTAH	Lease Designation and Number:

EFFECTIVE DATE OF TRANSFER: 1/6/2006

CURRENT OPERATOR

N2115

Company: Westport Oil and Gas Company
Address: 1368 South 1200 East
city Vernal state UT zip 84078
Phone: (435) 789-4433
Comments:

Name: Carroll Estes
Signature: Carroll Estes
Title: Principal Environmental Specialist
Date: 12/14/2006

NEW OPERATOR

N2995

Company: Kerr McGee Oil and Gas Company, LP
Address: 1368 South 1200 East
city Vernal state UT zip 84078
Phone: (435) 789-4433
Comments:

Name: Carroll Estes
Signature: Carroll Este
Title: Staff Environmental Specialist
Date: 12/14/2006

(This space for State use only)

Transfer approved by: Dan Jarvis
Title: UIC Geologist

Approval Date: 12/20/06

Comments:
Only applies to Wellington Fed 44-6 and Wellington Fed 22-04.
All other wells are in Indian Country and need EPA approval

RECEIVED
DEC 15 2006
DIV. OF OIL, GAS & MINING

(5/2000)

Form 3160-5
(August 1999)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
OMB No. 1004-0135
Expires Jnovember 30, 2000

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or reenter an abandoned well. Use Form 3160-3 (APD) for such proposals.

SUBMIT IN TRIPLICATE – Other instructions on reverse side

5. Lease Serial No.
MULTIPLE LEASES

6. If Indian, Allottee or Tribe Name

7. If Unit or CA/Agreement, Name and/or No.

1. Type of Well
☐ Oil Well ☒ Gas Well ☐ Other

2. Name of Operator
KERR-McGEE OIL & GAS ONSHORE LP

3a. Address
1368 SOUTH 1200 EAST VERNAL, UT 84078

3b. Phone No. *(include area code)*
(435) 781-7024

4. Location of Well *(Footage, Sec., T., R., M., or Survey Description)*
SEE ATTACHED

8. Well Name and No.
MUTIPLE WELLS

9. API Well No.

10. Field and Pool, or Exploratory Area

11. County or Parish, State
UINTAH COUNTY, UTAH

12. CHECK APPROPRIATE BOX(ES) TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION			
☐ Notice of Intent	☐ Acidize	☐ Deepen	☐ Production (Start/Resume)	☐ Water Shut-Off
	☐ Alter Casing	☐ Fracture Treat	☐ Reclamation	☐ Well Integrity
☒ Subsequent Report	☐ Casing Repair	☐ New Construction	☐ Recomplete	☒ Other CHANGE OF OPERATOR
	☐ Change Plans	☐ Plug and Abandon	☐ Temporarily Abandon	
☐ Final Abandonment Notice	☐ Convert to Injection	☐ Plug Back	☐ Water Disposal	

13. Describe Proposed or Completed Operations (clearly state all pertinent details, including estimated starting date of any proposed work and approximate duration thereof. If the proposal is to deepen directionally or recomplete horizontally, give subsurface locations and measured and true vertical depths of all pertinent markers and zones. Attach the Bond under which the work will be performed or provide the Bond No. on file with BLM/BIA. Required subsequent reports shall be filed within 30 days following completion of the involved operations. If the operation results in a multiple completion or recompletion in a new interval, a Form 3160-4 shall be filed once testing has been completed. Final Abandonment Notices shall be filed only after all requirements, including reclamation, have been completed, and the operator has determined that the site is ready for final inspection.

PLEASE BE ADVISED THAT KERR-McGEE OIL & GAS ONSHORE LP, IS CONSIDERED TO BE THE OPERATOR OF THE ATTACHED WELL LOCATIONS. EFFECTIVE JANUARY 6, 2006.
KERR-McGEE OIL & GAS ONSHORE LP, IS RESPONSIBLE UNDER TERMS AND CONDITIONS OF THE LEASE(S) FOR THE OPERATIONS CONDUCTED UPON LEASE LANDS. BOND COVERAGE IS PROVIDED BY STATE OF UTAH NATIONWIDE BOND NO. RLB0005237.

RECEIVED
MAY 10 2006
DIV. OF OIL, GAS & MINING

BLM BOND = C01203
BIA BOND = RLB0005239

APPROVED 5/16/06
Earlene Russell
Division of Oil, Gas and Mining
Earlene Russell, Engineering Technician

14. I hereby certify that the foregoing is true and correct
Name *(Printed/Typed)*
RANDY BAYNE

Title
DRILLING MANAGER

Signature
Randy Bayne

Date
May 9, 2006

THIS SPACE FOR FEDERAL OR STATE USE

Approved by	Title	Date
Conditions of approval, if any, are attached. Approval of this notice does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.	Office	

Title 18 U.S.C. Section 1001, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

(Instructions on reverse)

Form 3160-5
(August 1999)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
OMB No. 1004-0135
Expires Jnovember 30, 2000

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or reenter an abandoned well. Use Form 3160-3 (APD) for such proposals.

SUBMIT IN TRIPLICATE – Other instructions on reverse side

5. Lease Serial No.
MULTIPLE LEASES

6. If Indian, Allottee or Tribe Name

7. If Unit or CA/Agreement, Name and/or No.

1. Type of Well
☐ Oil Well ☒ Gas Well ☐ Other

8. Well Name and No.
MUTIPLE WELLS

2. Name of Operator
WESTPORT OIL & GAS COMPANY L.P.

9. API Well No.

3a. Address
1368 SOUTH 1200 EAST VERNAL, UT 84078

3b. Phone No. *(include area code)*
(435) 781-7024

10. Field and Pool, or Exploratory Area

4. Location of Well *(Footage, Sec., T., R., M., or Survey Description)*

SEE ATTACHED

11. County or Parish, State
UINTAH COUNTY, UTAH

12. CHECK APPROPRIATE BOX(ES) TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION			
☐ Notice of Intent	☐ Acidize	☐ Deepen	☐ Production (Start/Resume)	☐ Water Shut-Off
	☐ Alter Casing	☐ Fracture Treat	☐ Reclamation	☐ Well Integrity
☒ Subsequent Report	☐ Casing Repair	☐ New Construction	☐ Recomplete	☒ Other CHANGE OF OPERATOR
	☐ Change Plans	☐ Plug and Abandon	☐ Temporarily Abandon	
☐ Final Abandonment Notice	☐ Convert to Injection	☐ Plug Back	☐ Water Disposal	

13. Describe Proposed or Completed Operations (clearly state all pertinent details, including estimated starting date of any proposed work and approximate duration thereof. If the proposal is to deepen directionally or recomplete horizontally, give subsurface locations and measured and true vertical depths of all pertinent markers and zones. Attach the Bond under which the work will be performed or provide the Bond No. on file with BLM/BIA. Required subsequent reports shall be filed within 30 days following completion of the involved operations. If the operation results in a multiple completion or recompletion in a new interval, a Form 3160-4 shall be filed once testing has been completed. Final Abandonment Notices shall be filed only after all requirements, including reclamation, have been completed, and the operator has determined that the site is ready for final inspection.

EFFECTIVE JANUARY 6, 2006, WESTPORT OIL & GAS COMPANY L.P., HAS RELINQUISHED THE OPERATORSHIP OF THE ATTACHED WELL LOCATIONS TO KERR-McGEE OIL & GAS ONSHORE LP.

APPROVED 5/16/06
Earlene Russell
Division of Oil, Gas and Mining
Earlene Russell, Engineering Technician

RECEIVED
MAY 10 2006
DIV. OF OIL, GAS & MINING

14. I hereby certify that the foregoing is true and correct

Name *(Printed/Typed)*	Title
BRAD LANEY	ENGINEERING SPECIALIST
Signature	Date May 9, 2006

THIS SPACE FOR FEDERAL OR STATE USE

Approved by Brad Laney	Title	Date 5-9-06
Conditions of approval, if any, are attached. Approval of this notice does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.	Office	

Title 18 U.S.C. Section 1001, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

(Instructions on reverse)

United States Department of the Interior

BUREAU OF LAND MANAGEMENT
Colorado State Office
2850 Youngfield Street
Lakewood, Colorado 80215-7076

IN REPLY REFER TO:
CO922 (MM)
3106
COC017387 et. al.

March 23, 2006

NOTICE

Kerr-McGee Oil & Gas Onshore L.P.	:	
1999 Broadway, Suite 3700	:	Oil & Gas
Denver, CO 80202	:	

Merger/Name Change - Recognized

On February 28, 2006 this office received acceptable evidence of the following mergers and name conversion:

> Kerr-McGee Oil & Gas Onshore L.P., a Delaware Limited Partnership, and Kerr-McGee Oil & Gas Onshore LLC, a Delaware Limited Partnership merger with and into Westport Oil and Gas Company L.P., a Delaware Limited Partnership, and subsequent Westport Oil & Gas Company L.P. name conversion to Kerr-McGee Oil & Gas Onshore L.P.

For our purposes the merger and name conversion was effective January 4, 2006, the date the Secretary of State of Delaware authenticated the mergers and name conversion.

Kerr-McGee Oil & Gas Onshore L.P. provided a list of oil and gas leases held by the merging parties with the request that the Bureau of Land Management change all their lease records from the named entities to the new entity, Kerr-McGee Oil & Gas Onshore L.P. In response to this request each state is asked to retrieve their own list of leases in the names of these entities from the Bureau of Land Management's (BLM) automated LR2000 data base.

The oil and gas lease files identified on the list provided by Kerr-McGee Oil & Gas Onshore L.P. have been updated as to the merger and name conversion. We have not abstracted the lease files to determine if the entities affected by the acceptance of these documents holds an interest in the lease, nor have we attempt to identify leases where the entity is the operator on the ground that maintains vested record title or operating rights interests. If additional documentation, for change of operator, is required you will be contacted directly by the appropriate Field Office. The Mineral Management Services (MMS) and other applicable BLM offices were notified of the merger with a copy of this notice

Please contact this office if you identify additional leases where the merging party maintains an interest, under our jurisdiction, and we will document the case files with a copy of this notice. If the leases are under the jurisdiction of another State Office that information will be forwarded to them for their action.

Three riders accompanied the merger/name conversion documents which will add Kerr-McGee Oil and Gas Onshore LLC as a principal to the 3 Kerr-McGee bonds maintained by the Wyoming State Office. These riders will be forward to them for their acceptance.

The Nationwide Oil & Gas Continental Casualty Company Bond #158626364 (BLM Bond #CO1203), maintained by the Colorado State Office, will remain in full force and effect until an assumption rider is accepted by the Wyoming State Office that conditions their Nationwide Safeco bond to accept all outstanding liability on the oil and gas leases attached to the Colorado bond.

If you have questions about this action you may call me at 303.239.3768.

/s/Martha L. Maxwell
Martha L. Maxwell
Land Law Examiner
Fluid Minerals Adjudication

Attachment:
List of OG Leases to each of the following offices:
MMS MRM, MS 357B-1
WY, UT, NM/OK/TX, MT/ND, WY State Offices
CO Field Offices
Wyoming State Office
Rider #1 to Bond WY2357
Rider #2 to Bond WY1865
Rider #3 to Bond WY1127

United States Department of the Interior

BUREAU OF LAND MANAGEMENT
Utah State Office
P.O. Box 45155
Salt Lake City, UT 84145-0155
http://www.blm.gov

TAKE PRIDE IN AMERICA

IN REPLY REFER TO:
3106
(UT-922)

March 27, 2006

Memorandum

To: Vernal Field Office

From: Chief, Branch of Fluid Minerals

Subject: Merger Approval

Attached is an approved copy of the merger recognized by the Bureau of Land Management, Colorado State Office. We have updated our records to reflect the merger from Westport Oil and Gas Company L.P. into Kerr-McGee Onshore Oil and Gas Company. The merger was approved effective January 4, 2006.

Chief, Branch of
Fluid Minerals

Enclosure
Approval letter from BLM COSO (2 pp)

cc: MMS, Reference Data Branch, James Sykes, PO Box 25165, Denver CO 80225
State of Utah, DOGM, Attn: Earlene Russell, PO Box 145801, SLC UT 84114
Teresa Thompson
Joe Incardine
Connie Seare
Dave Mascarenas
Susan Bauman

RECEIVED
MAR 2 8 2006
DIV. OF OIL, GAS & MINING

43-047-30359
20 9S 20E

eog resources

EOG Resources, Inc.
1060 E Hwy 40
Vernal, Utah 84078

Certified Mail
7010 1670 0001 2225 8651

February 14, 2011

RECEIVED
FEB 17 2011
DIV. OF OIL, GAS & MINING

United States Environmental Protection Agency
Region 8
Attn: Nathan Wiser
Mail Stop: 8ENF-UFO
1595 Wynkoop Street
Denver, CO 80202

RE: Chapita Wells Unit 550-30N
EPA Permit No. UT20980-06509

Chapita Wells Unit SWD 2-29
EPA Permit No. UT 21049-07108

Hoss SWD 903-36
EPA Permit No. UT21158-07866

Hoss SWD 905-31
EPA Permit No. UT21160-07868

Hoss SWD 907-31
EPA Permit No. UT21162-07870

Natural Buttes Unit 21-20B
EPA Permit No. UT20623-03708

Hoss SWD 901-36
EPA Permit No. UT21157-07865

Hoss SWD 904-36
EPA Permit No. UT21159-07867

Hoss SWD 906-31
EPA Permit No. UT21161-07869

Dear Mr. Wiser:

Please find enclosed the Annual Disposal/Injection Well Monitoring Report (EPA Form 7520-11) for the above referenced wells. As requested, I have enclosed a copy of the water analysis for the water that we inject into each well. The water that is injected into the Chapita Wells Unit 550-30N and Chapita Wells Unit SWD 2-29 wells is pumped from the same facility located at the Chapita Wells 550-30N well site. All of the produced water that is injected into the six Hoss disposal wells is pumped from a single disposal facility (Hoss SWD Facility). We received the authorization to inject into the Hoss SWD 906-31 well on January 14, 2010. It was the last approval that we needed to operate the facility. We commenced injection from the Hoss SWD facility to all 6 Hoss SWD wells on that date. I have included a copy of the water analysis for that facility as well. The produced water that is injected into the NBU 21-20B comes from its own facility. I have also included a copy of the water analysis for that facility.

EOG Resources, Inc.
1060 E Hwy 40
Vernal, Utah 84078

We ran the required Temperature Logs on the Chapita Wells Unit 1125-29 (AOR well for the Chapita Wells Unit SWD 2-29 well), Chapita Wells Unit 47-30 (AOR well for the Chapita Wells Unit 550-30N SWD), and the Chapita 550-30N SWD and submitted logs in December. They are required on an annual basis. We are also required to run Temperature logs for the AOR wells associated with the six Hoss Disposal Wells and pressure surveys on the six disposal wells. I have included copies of the Temperature logs for the AOR wells listed below and the results of the pressure surveys for the disposal wells (see table).

Well	Hoss 901	Hoss 903	Hoss 904	Hoss 905	Hoss 906	Hoss 907
Fluid level	Surface	Surface	Surface	Surface	12 ft.	Surface
Pore Pressure (psig)	934 psig	1029 psig	1119 psig	936 psig	927 psig	912 psig
AOR Well	Hoss 1-36	Hoss 2-36	Hoss 62-36	Federal 23-31	Hoss 8-31	Hoss 8-31
AOR Well	Hoss 10-31	Hoss 5-36		N. Chapita Federal 24-31	Hoss 9-31	
AOR Well	N.Chapita Federal 44-36				N.Chapita Federal 43-31	

I ran pore pressure test on two wells per day for three days. I have digital Excel spreadsheet files of the pore pressure tests from Production Logging Services that I can forward to if you would like (350 pages each in hard copy). We have not started construction on the Coyote SWD 1-16 well (EPA Permit No. UT22165-08747) but we plan to do so soon. If you need any other information from me, I can be reached at (435) 781-9100 (office) or (435) 828-8236 (cell).

Sincerely,

Ed Forsman

Ed Forsman
Production Engineering Advisor
EOG Resources – Vernal Operations

Attachments

cc: State of Utah-Division of Oil, Gas & Mining
BLM - Vernal Field Office
Jim Schaefer – Denver Office
Dave Long – Big Piney Office

OMB No. 2040-0042 Approval Expires 1/31/05

EPA

United States Environmental Protection Agency
Washington, DC 20460

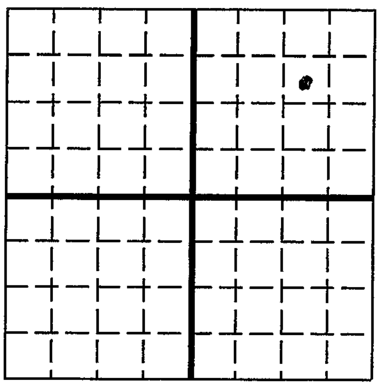
ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT

Name and Address of Existing Permittee	Name and Address of Surface Owner
EOG Resources, Inc. 1060 East Highway 40 Vernal, UT 84078	Bureau of Land Management 170 South 500 East Vernal UT 84078

Locate Well and Outline Unit on Section Plat - 640 Acres

N

W



E

S

State	County	Permit Number
Utah	Uintah County	UT20623-03708

Surface Location Description

N 1/4 of E 1/4 of N 1/4 of E 1/4 of Section 20 Township 09S Range 20E

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location 1037 ft. frm (N/S) NL Line of quarter section
and 1033 ft. from (E/W) EL Line of quarter section.

WELL ACTIVITY

- [x] Brine Disposal
- [ ] Enhanced Recovery
- [ ] Hydrocarbon Storage

TYPE OF PERMIT

- [x] Individual
- [ ] Area

Number of Wells 1

Lease Name Natural Buttes Well Number NBU 21-20B

	INJECTION PRESSURE		TOTAL VOLUME INJECTED		TUBING -- CASING ANNULUS PRESSURE (OPTIONAL MONITORING)	
MONTH YEAR	AVERAGE PSIG	MAXIMUM PSIG	BBL	MCF	MINIMUM PSIG	MAXIMUM PSIG
January-2010	424	425	16898	0	0	0
February-2010	423	425	15091	0	0	0
March-2010	425	425	15602	0	0	0
April-2010	417	475	18697	0	0	0
May-2010	432	450	18073	0	0	0
June-2010	438	450	13043	0	0	0
July-2010	425	425	340	0	0	0
August-2010	200	200	439	0	0	0
September-2010	349	429	15167	0	0	0
October-2010	443	475	15012	0	0	0
November-2010	472	475	11240	0	0	0
December-2010	469	480	9166	0	0	0

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibliity of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Ed Forsman - Production Engineering Advisor	Ed Forsman	02/12/10

PAPERWORK REDUCTION ACT

The public reporting and record keeping burden for this collection of information is estimated to average 25 hours annually for operators of Class I wells and 5 hours annually for operators of Class II wells. Burden means the total time, effort, or financial resource expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822), 1200 Pennsylvania Ave., NW, Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed forms to this address.

NALCO

1465 East 1650 south Vernal UT 84078 (435) 789-2069 www.nalco.com

Water Analysis Report

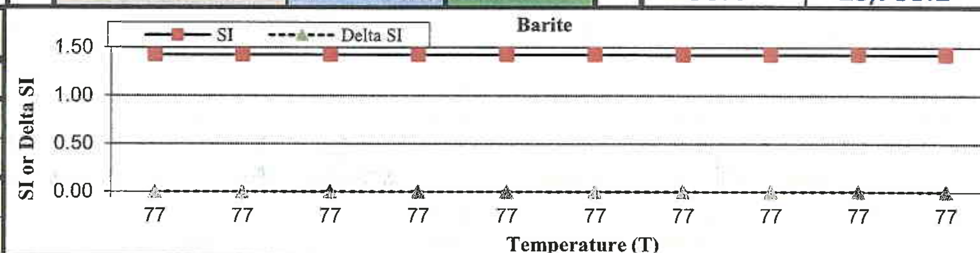
Field :	EOG	**Sample Date :**	1/20/2011
County :		**Formation :**	
Location :	SWD 21-20	**Rock Type :**	
Lab ID :		**Depth :**	**Analysed Date:** 1/20/2011
Comments :			

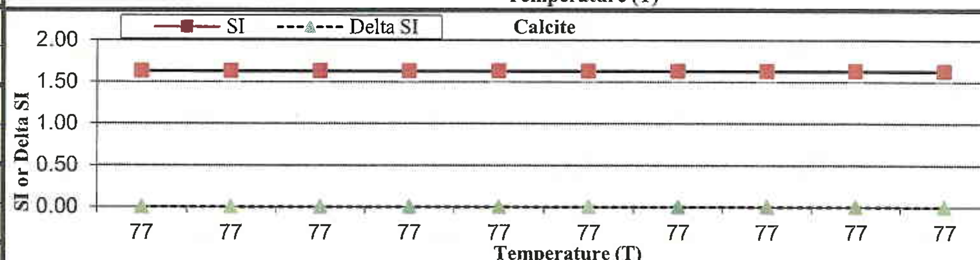
CATIONS	mg/l
Potassium	56.6
Sodium	9,509.6
Calcium	604.4
Magnesium	94.9
Iron	19.2
Barium	1.4
Strontium	24.2
SUM +	**10,310.3**

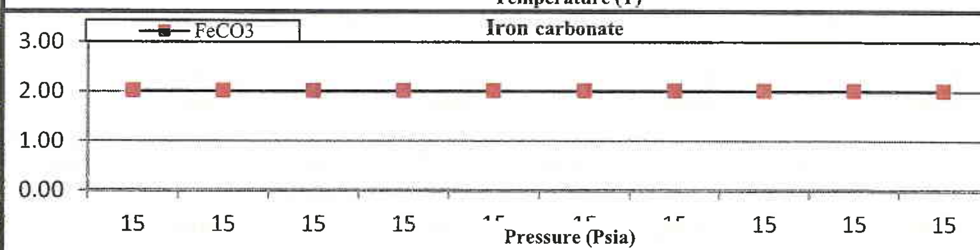
	Measured	Calculated
Total Dissolve Solid	32094.20	0.00
Total Hardness		1900.21
PH	7.23	0.00
Total H2S aq	0.00	0.00
Manganese	0.46	
PO4 Residual	0.00	
SRB Vials Turned	0.00	
APB Vials Turned	0.00	

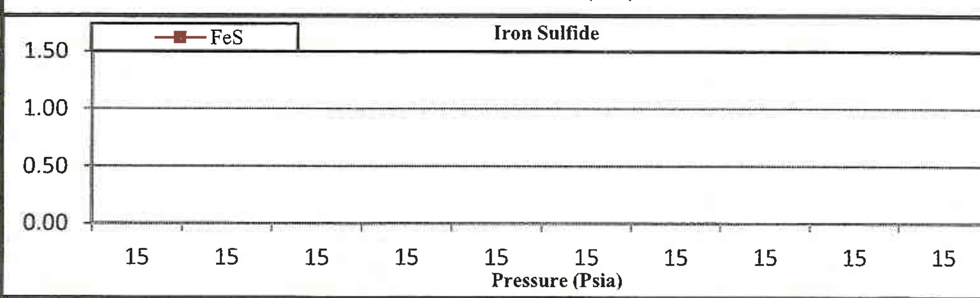
ANIONS	mg/l
Sulfate	1,310.0
Chloride	19,200.0
Carbonate	0.0
Bicarbonate	3,245.2
Bromide	0.0
Organic Acids	0.0
Hydroxide	0.0
SUM -	**23,755.2**

Initial(BH)	Final(WH)
Saturation Index values	
Calcite ($CaCO_3$)	
1.63	1.63
Barite ($BaSO_4$)	
1.42	1.42
Halite (NaCl)	
-2.57	-2.57
Gypsum	
-0.57	-0.57
Hemihydrate	
-1.33	-1.33
Anhydrite	
-0.82	-0.82
Celestite	
-0.34	-0.34
Iron Sulfide	
0.00	0.00
Zinc Sulfide	
0.00	0.00
Calcium fluoride	
0.00	0.00
Iron Carbonate	
2.01	2.01
Inhibitor needed (mg/L)	
Calcite	NTMP
0.16	0.16
Barite	BHPMP
0.31	0.31









Lab Manager: Andrea Craig

Analysis by:

Division of Oil, Gas and Mining

OPERATOR CHANGE WORKSHEET (for state use only)

ROUTING
CDW

X - Change of Operator (Well Sold) Operator Name Change/Merger

The operator of the well(s) listed below has changed, effective: **12/31/1986**

FROM: (Old Operator):	**TO:** (New Operator):
N2995-Kerr-McGee Oil & Gas Onshore, LP 1368 South 1200 East Vernal, UT 84078 Phone: 1 (435) 781-7024	N9550-EOG Resources, Inc. 1060 E Hwy 40 Vernal, UT 84078 Phone: 1 (435) 781-9157

CA No. **Unit:**

WELL NAME	SEC	TWN	RNG	API NO	ENTITY NO	LEASE TYPE	WELL TYPE	WELL STATUS
NBU 21-20B	20	090S	200E	4304730359	99998	Federal	WD	A

OPERATOR CHANGES DOCUMENTATION

Enter date after each listed item is completed

1. (R649-8-10) Sundry or legal documentation was received from the **FORMER** operator on: n/a
2. (R649-8-10) Sundry or legal documentation was received from the **NEW** operator on: 1/11/2012
3. The new company was checked on the **Department of Commerce, Division of Corporations Database on:** 12/5/2011

4a. Is the new operator registered in the State of Utah: yes Business Number: 966901-0143

5a. (R649-9-2)Waste Management Plan has been received on: IN PLACE

5b. Inspections of LA PA state/fee well sites complete on: n/a

5c. Reports current for Production/Disposition & Sundries on: ok

6. **Federal and Indian Lease Wells:** The BLM and or the BIA has approved the merger, name change, or operator change for all wells listed on Federal or Indian leases on: BLM n/a BIA n/a
7. **Federal and Indian Units:**
   The BLM or BIA has approved the successor of unit operator for wells listed on: n/a
8. **Federal and Indian Communization Agreements ("CA"):**
   The BLM or BIA has approved the operator for all wells listed within a CA on: n/a
9. **Underground Injection Control ("UIC")** Division has approved UIC Form 5 Transfer of Authority to **Inject,** for the enhanced/secondary recovery unit/project for the water disposal well(s) listed on: n/a

DATA ENTRY:

1. Changes entered in the **Oil and Gas Database on:** 1/12/2012
2. Changes have been entered on the **Monthly Operator Change Spread Sheet on:** 1/12/2012
3. Bond information entered in RBDMS on: n/a
4. Fee/State wells attached to bond in RBDMS on: n/a
5. Injection Projects to new operator in RBDMS on: n/a
6. Receipt of Acceptance of Drilling Procedures for APD/New on: n/a

BOND VERIFICATION:

1. Federal well(s) covered by Bond Number: NM2308
2. Indian well(s) covered by Bond Number: n/a

3a. (R649-3-1) The **NEW** operator of any state/fee well(s) listed covered by Bond Number n/a

3b. The **FORMER** operator has requested a release of liability from their bond on: n/a

LEASE INTEREST OWNER NOTIFICATION:

4. (R649-2-10) The **NEW** operator of the fee wells has been contacted and informed by a letter from the Division of their responsibility to notify all interest owners of this change on: n/a

COMMENTS: Correction to correct non-unit WD well - out of unit (but within unit boundaries) not operated by unit operator. Confirmed with KMG's Land Manager.

/

STATE OF UTAH
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL, GAS AND MINING

FORM 9

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill new wells, significantly deepen existing wells below current bottom-hole depth, reenter plugged wells, or to drill horizontal laterals. Use APPLICATION FOR PERMIT TO DRILL form for such proposals.

5. LEASE DESIGNATION AND SERIAL NUMBER: UTU0144869
6. IF INDIAN, ALLOTTEE OR TRIBE NAME: UTE INDIAN TRIBE SURFACE
7. UNIT or CA AGREEMENT NAME:
8. WELL NAME and NUMBER: NBU 21-20B
9. API NUMBER: 4304730359
10. FIELD AND POOL, OR WILDCAT: NATURAL BUTTES

1. TYPE OF WELL: OIL WELL ☐ GAS WELL ☐ OTHER WATER DISPOSAL WELL

2. NAME OF OPERATOR: EOG RESOURCES, INC.

3. ADDRESS OF OPERATOR: 1060 EAST HWY 40 CITY VERNAL STATE UT ZIP 84078 PHONE NUMBER: (435) 781-9157

4. LOCATION OF WELL

FOOTAGES AT SURFACE: 1037' FNL 1033' FEL

COUNTY: UINTAH

QTR/QTR, SECTION, TOWNSHIP, RANGE, MERIDIAN: NENE 20 9S 20E S

STATE: UTAH

11. CHECK APPROPRIATE BOXES TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION		
☐ NOTICE OF INTENT (Submit in Duplicate) Approximate date work will start:	☐ ACIDIZE	☐ DEEPEN	☐ REPERFORATE CURRENT FORMATION
	☐ ALTER CASING	☐ FRACTURE TREAT	☐ SIDETRACK TO REPAIR WELL
	☐ CASING REPAIR	☐ NEW CONSTRUCTION	☐ TEMPORARILY ABANDON
	☐ CHANGE TO PREVIOUS PLANS	☐ OPERATOR CHANGE	☐ TUBING REPAIR
☑ SUBSEQUENT REPORT (Submit Original Form Only) Date of work completion:	☐ CHANGE TUBING	☐ PLUG AND ABANDON	☐ VENT OR FLARE
	☐ CHANGE WELL NAME	☐ PLUG BACK	☐ WATER DISPOSAL
	☐ CHANGE WELL STATUS	☐ PRODUCTION (START/RESUME)	☐ WATER SHUT-OFF
	☐ COMMINGLE PRODUCING FORMATIONS	☐ RECLAMATION OF WELL SITE	☑ OTHER: Change of Operator
	☐ CONVERT WELL TYPE	☐ RECOMPLETE - DIFFERENT FORMATION	

12. DESCRIBE PROPOSED OR COMPLETED OPERATIONS. Clearly show all pertinent details including dates, depths, volumes, etc.

EOG Resources, Inc. respectfully requests the operator of the above referenced well be corrected (effective December 31, 1986) and show EOG Resources, Inc. as the current operator. EOG assumes all rights, title and interest in the well as described above.

Belco Development Corporation assigned all of its right, title and interest in the well as described above to Enron Oil & Gas Company and relinquished and transferred operatorship of all of the Subject Well to Enron Oil & Gas Company, December 31, 1986. Enron Oil & Gas Company assigned all of its right, title and interest in the well as described above to EOG Resources, Inc. and relinquished and transferred operatorship of all of the Subject Well to EOG Resources, Inc. August 30, 1999. Until early 1992 the referenced well was a producing gas well. August 17, 1992, EOG submitted a Subsequent Report Sundry to the State of Utah noting NBU 21-20B had been successfully converted to a Water Disposal Well and was no longer a producing gas well within the Natural Buttes Unit then operated by Coastal Oil & Gas and subsequently El Paso Production Oil and Gas Company, subsequently Westport Oil & Gas, subsequently Kerr McKee.

BOND NM2308

NAME (PLEASE PRINT) Kaylene R. Gardner TITLE Sr. Regulatory Specialist

SIGNATURE [signature] DATE 1/11/2012

(This space for State use only)

RECEIVED
JAN 1 1 2012
DIV. OF OIL, GAS & MINING

APPROVED 1/12/2012
Earlene Russell
Division of Oil, Gas and Mining
Earlene Russell, Engineering Technician

(5/2000) (See Instructions on Reverse Side)